2006 STATE OF THE MARKET REPORT

THE MIDWEST ISO

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FOR THE MIDWEST ISO

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I. Executive Summary

This report provides a detailed evaluation of the Midwest ISO ("MISO") energy markets for 2006, first full year of market operations in Midwest ISO. The markets enjoyed a relatively smooth introduction in 2005 and continued to operate without significant disruptions in 2006. This experience is notable given the expansive geographic scope of the Midwest ISO markets and the fundamental transition required as the region changed from a wholesale market that relied solely on bilateral trading to a centrally-coordinated wholesale energy market. Good coordination is essential due to the physical characteristics of electricity and the transmission network used to deliver electricity to customers.

Overall, we found that the market performed competitively in 2006. Although a number of individual 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. Hence, the mitigation measures that are designed to prevent abuses of market power were employed relatively infrequently.

In fact, electricity prices in Midwest ISO markets declined in 2006 by nearly 20 percent when compared to average Midwest ISO prices in 2005. We attribute the decline primarily to lower fuel prices, which trended down in 2006 after the relatively high price levels of late 2005. Generally lower load levels in 2006 also contributed to the lower power prices. While the year saw new record peak loads in July, and again in early August, overall load levels were slightly lower in 2006 on average.

A. Introduction

Midwest ISO electricity markets facilitate the use of the lowest-cost supplies to meet real-time demand for energy, while respecting reliability requirements for reserves and preventing power flows on the network from exceeding transmission constraints. The markets produce locational marginal prices ("LMPs") that reflect the marginal system cost of serving load at each location on the network. When the market is functioning well, these prices not only provide transparent price signals that promote efficient operation of the system in the short term, they also facilitate efficient forward contracting and are a primary component of the long-term incentives that guide generation and transmission investment and retirement decisions.

In addition to the energy markets, the Midwest ISO issues and administers a market for financial transmission rights ("FTRs") that allows participants to hedge congestion between various locations. In order to move toward a complete set of wholesale markets that more fully reflects the reliability demands of the system, the Midwest ISO is working to develop ancillary services markets and alternatives for addressing resource adequacy. The proposed ancillary services markets are intended to ensure that the least-cost generating resources are selected to satisfy both the energy and reserve requirements of the regions and to ensure prices reflect the marginal cost of satisfying these requirements.

The MISO 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.

- First, the day-ahead market facilitates substantial improvements in the daily commitment of generating resources in the region. These efficiency improvements are achieved by reducing the quantity of generation that is committed and by ensuring that the most economic generation is committed.

- Second, the MISO energy markets reduce total dispatch costs by ensuring that energy is produced from the most economic resources given the limits of the transmission system. This includes employing the lowest-cost redispatch options to manage congestion when transmission constraints are binding, ultimately allowing the transmission system to be much more fully utilized.

- Third, the Midwest ISO energy markets improve reliability because the 5-minute dispatch provides much more responsive and accurate control of power flows on the transmission system. Previously, the region relied on Transmission Loading Relief procedures ("TLRs") to manage flows over constrained transmission interfaces. As we have shown in prior reports, the TLR process results in inefficient generator redispatch and its effects on the power flows are lagged and uncertain, which compels operators to intervene more heavily to achieve the same level of reliability as a centrally-coordinated LMP market.

- Finally, the newly-introduced energy markets provide transparent economic signals to guide short- and long-run decisions by participants and regulators. These signals may provide the most significant benefit of the markets because the benefits accumulate over time as improved investment and retirement decisions are made. Unfortunately, these long-run developments are also the least quantifiable of all of the benefits of the MISO's markets.

In addition to providing a summary of the prices, load, and other market outcomes in 2006, this report includes assessments of the following: the competitive performance of the markets; the operation of the day-ahead and real-time markets; the adequacy of the supply and economic signals provided by the markets; the management of congestion during 2006; and the coordination of transactions with adjacent areas. Our findings and recommendations in these areas are summarized and discussed below.

B. Energy Prices and Net Revenue in 2006

Prices in the Midwest ISO energy markets in 2006 were considerably lower than in 2005. The decrease was primarily attributable to significantly decreased natural gas, oil, and coal prices. In addition, although the Midwest ISO experienced record demand at the peak periods in 2006, relatively mild load overall contributed to lower prices. Midwest ISO experienced record demand of 114 GW in late July and 116 GW in early August.[1] Excluding Louisville Gas and Electric, which left the Midwest ISO in 2006, there were 21 hours in which load exceeded 105 GW as compared to 6 hours in 2005. Apart from these super-peak conditions, however, load levels in peak periods were generally higher in 2005. For example, load exceeded 100 GW in 39 hours in 2006 compared to 54 hours in 2005.

While more moderate load in 2006 did contribute to lower prices, prices were most heavily influenced by natural gas and oil prices. The report shows that the Midwest ISO's energy prices are highly correlated to natural gas prices in the region. This correlation is expected because generators fired by natural gas are frequently setting the price in peak hours (i.e., "on the margin"), and fuel costs represent the vast majority of variable costs for most generators.

In evaluating wholesale electricity price signals, it is useful to estimate the "net revenue" that a new generating unit would earn in a market. Net revenue is the revenue that a new generator would earn above its variable production costs if it runs when it is economic and does not run when it is not economic. A well-designed market should produce net revenues sufficient to finance new investment when demands on the system for energy and reserves begin to exceed resource availability. Even when the system is in a 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.).

[1] The record peak load of 116 GW includes LGEE system load. The remaining year-to-year comparisons exclude LGEE.

The net revenue analysis shows that even in the highest-price regions, Wisconsin-Upper Michigan ("WUMS") and southeast Minnesota, a new natural gas-fired generator would not have earned net revenues in 2006 sufficient to justify new investment. This outcome is a concern because the report also shows that actual capacity margins relative to forecasted peak demand for 2007 are very low throughout the Midwest ISO. We estimate capacity margins during the forecasted summer peak in 2007 of 5.5 percent excluding curtailable load and 12.7 including the curtailable load. These capacity margins include reliance on more than 7,000 MW of firm imports. Reliance on imports from other regions will continue to grow without significant investment in new generation or demand-response resources in the Midwest.

The fact that net revenues are not currently sufficient to support new entry is due in part to the Midwest ISO markets remaining incomplete. In particular:

- Net revenue high enough to support new entry requires either a significant number of price spikes associated with reserve shortages or capacity market revenues – the Midwest ISO had neither in 2006.
- The Midwest ISO currently lacks ancillary service revenues, which can provide substantial net revenue for resources such as combustion turbines that are called upon to produce energy in only a small share of the hours.

As excess capacity in the region declines, it will be important that the Midwest ISO has markets in place to send efficient long-term signals. Ancillary services markets can contribute to the provision of efficient long-term signals. In February 2007, Midwest ISO filed for FERC approval of ancillary service markets for Regulating Reserves and Contingency Reserves. Such markets would allow the Midwest ISO's markets to more fully reflect the reliability requirements of the region and will ensure that the region's energy prices reflect the trade-offs that must be made between operating reserves and energy when the system is in shortage. The development of these markets should be among the Midwest ISO's highest priorities.

Additionally, the Midwest ISO's tariff includes certain capacity requirements in Module E. This Module requires that load-serving entities designate network resources sufficient to cover their peak load, plus a specified margin. However, the specification of what types of resources and/or firm contracts will satisfy these requirements are unclear and there is very little enforcement authority currently in the Tariff. If these requirements were clear and well-enforced, it would allow a decentralized contract market to develop to satisfy these capacity requirements that would improve the market signals when new resources are needed. Hence, we support the work the Midwest ISO is currently doing with its participants and the States to make improvements in these areas. These changes will help assure the adequacy of resources in the Midwest ISO.

C. Day-Ahead Market Performance

The performance of the day-ahead market is very important because:

- The day-ahead market governs most generator commitments in the Midwest ISO – hence, efficient commitment requires efficient day-ahead market results.
- Most wholesale energy bought or sold through the Midwest ISO markets is settled at day-ahead market prices.
- Payments to FTR holders are based on the day-ahead market prices.

The Midwest ISO markets have substantially improved the commitment and dispatch of generating resources in the Midwest. The improved commitment was largely attributable to the day-ahead market, which provides a market-based process to commit generating resources. In 2006, the percentage of generation dispatched to meet load scheduled through the day-ahead market increased to 98 percent, up from less than 97 percent in 2005. On average, 2 percent of supply in 2006 was committed after the day-ahead market by market participants (i.e., self-committed) or by the Midwest ISO to meet anticipated energy and reserve needs and manage congestion in real time (i.e., reliability assessment commitments or "RAC").

One reason that generation is not fully scheduled in the day-ahead market is that the load is also slightly under-scheduled (i.e., less than real-time load), particularly under the highest-load conditions. Load scheduling in the day-ahead market in 2006 was significantly higher than in 2005, increasing from 94.7 percent to 96.1 percent. When load is under-scheduled, it can cause the system operator to commit additional generators. The underscheduling is consistent with the price signals produced by the markets, i.e., increased purchases in the day-ahead market would cause the day-ahead prices to be significantly higher than the real-time prices. One reason that prices in the real-time are not higher, which would provide the signal needed for the load to be more fully scheduled in the day-ahead market, is that the peaking resources relied on to meet the incremental load in real time frequently do not set prices in the real-time market. To address this issue, this report reiterates a recommendation made in 2005 that the Midwest ISO consider changes to its real-time pricing to allow peaking resources to more frequently set energy prices when appropriate. Work is underway to identify the changes in market rules and software that will be necessary to address this issue.

One important aspect of the markets' performance is how well the day-ahead prices converge with the real-time prices. The report shows that the prices in the day-ahead market converged relatively well in most locations – convergence was comparable with other established markets. Price convergence is desirable because it promotes efficient commitment of generating resources and scheduling of external transactions.

The good convergence can be attributed in part to active virtual supply and demand participation in the day-ahead market. Virtual purchases and sales in the day-ahead market (which are bought or sold back in the real-time market because they do not correspond to physical resources or load) increased rapidly after the introduction of the energy markets. However, FERC issued an Order in April 2006 related to the allocation of Revenue Sufficiency Guarantee ("RSG") costs, which indicated that such costs should be allocated to virtual supply transactions. Immediately after this order, virtual transaction volumes decreased by roughly 50 percent. However, this reduction has not materially affected the convergence between day-ahead and real-time prices.

D. Real-Time Market Performance

The real-time market is the primary driver for the day-ahead market and all other forward electricity markets. It is straightforward that higher real-time prices will lead to higher day-ahead and other forward market prices. If day-ahead prices were regularly lower than real-time prices, buyers would tend to increase purchases day-ahead and sellers would decrease their day-ahead sales. In addition, increased volatility in the real-time market will also generally lead to higher day-ahead and forward market prices because forward purchases are a primary means to manage the risks associated with real-time price volatility.

In 2006, prices in the real-time market were substantially more volatile than in the day-ahead market, as expected. Being a purely physical market, there are always fewer dispatch options and more random factors in the real-time market than in the day-ahead market. Nonetheless, prices in this market should converge with prices in the day-ahead market when the markets are functioning well.

The locational real-time energy market accurately reflected the value of congestion in the Midwest. In 2006, the historically-congested path between Minnesota and the WUMS area was constrained far less frequently than in 2005. In part this was due to moderate loads, but a more significant factor was reduced imports from Canada (as well as some significant long-term generation outages). These same factors caused congestion to increase on the south-to-north transmission paths into Minnesota in the second half of 2006. The chronic congestion into the southeastern Minnesota area caused this area to be defined as a "Narrowly Constrained Area" or "NCA" for purposes applying market power mitigation measures. Under the bilateral markets that had prevailed prior to the introduction of the Midwest ISO energy markets, these patterns of congestion were not priced efficiently or transparently.

The performance of the real-time market is compromised in some cases by reduced dispatch flexibility offered by many generators. The average dispatchable range (EcoMax-EcoMin) for the Midwest ISO units was only 21 percent of the generators' capacity in 2006, while generators are capable of providing 50-60 percent on average. The reduced flexibility to move generation over its output range can limit redispatch options for managing congestion and, thereby, affect prices. The effects of generation inflexibility are discussed in more detail in the transmission congestion section of this report. The Midwest ISO filed and FERC approved a plan to provide incentives for generators to provide more flexibility.

RSG payments are made to ensure that the market revenue received by a generator when its offer is accepted exceeds its as-offered costs. RSG costs can be incurred in both the day-ahead and real-time markets. Resources committed after the day-ahead market to maintain reliability receive "real-time" RSG payments when their real-time revenues do not cover their as-bid costs.[2] RSG costs decreased sharply in 2006 from the levels that prevailed in 2005. In 2005, the real-time RSG costs averaged more than $50 million per month. These costs averaged less than $20 million per month in 2006. These costs can be caused by inefficient or excess commitment of non-peaking resources – our analysis did not show that this was a problem.

2 Because the day-ahead market is financial, a unit that is uneconomic will generally not be selected. Hence, day-ahead RSG costs average only $5 million per month.

Peaking resources received approximately 70 percent of the RSG payments in 2006, despite producing only 1 percent of the energy in the Midwest ISO. This occurs because they are generally the highest-cost resources and frequently do not set the energy price. The report shows that in a number of periods that exhibited particularly high RSG costs, these costs were due to specific transmission and generation outages that required unusually high commitments of peaking resources. While these RSG costs are unavoidable, RSG costs associated with other uses of peaking resources can be reduced by optimizing the commitment and dispatch of the peaking resources. The report finds that the Midwest ISO continued to improve its commitment and dispatch of peaking resources in 2006.

To achieve further improvements, we continue to recommend the development of a market-based model with the capability of looking ahead 1-2 hours to better dispatch peaking resources and manage the dispatch of slow-ramping generating resources. In the longer-term, we have proposed that the Midwest ISO develop rules that would increase the ability of peaking resources to set prices when they are needed to satisfy system needs. We also continue to consult with the Midwest ISO regarding of number of other provisions it has proposed that should improve system flexibility and reduce RSG payments. These include modifications to the dispatch and congestion-management algorithm and process, and modified RSG eligibility rules.

E. Peak Load Event in 2006

Pricing during shortage conditions plays a very important role in providing the economic signals to govern investment in generation, transmission, and demand response resources. Hence, it is important to critically evaluate peak-load events when the market is close to or in a shortage. Shortages occur when the resources in the market are insufficient to satisfy both the energy and operating reserves demands of the system.

One peak-load event occurred in 2006 in late July and early August. Beginning on July 31, the Midwest ISO region experienced record high temperatures in several areas, including a high temperature of 101 degrees in Minneapolis (18 degrees above normal high). The extremely high temperatures throughout the Midwest ISO region resulted in record electricity demand. On July 31, the Midwest ISO set a new all-time peak at more than 116 GW. The previous peak demand was 112 GW in 2005. The peak hourly load was over 114 GW on the other two peak days, August 1 and 2. Emergency procedures were invoked by the Midwest ISO and by PJM during the peak hours on these days. A higher-level emergency procedure was invoked on August 1 and 2, which resulted in voluntary load reductions of close to 3000 MW, as well as export curtailments of 400 to 800 MW. Absent these curtailments and load reductions, the load would have set new records. Additionally, the system would have been short of operating reserves without these actions, which would have triggered shortage pricing. In effect, this demand-side management artificially moderated energy prices.

Hourly real-time prices during the peak load event were somewhat erratic during the highest-demand hours. Prices ranged from $200 to $350 per MWh during the peak hours on July 31. Prices during the peak hours on August 1 generally ranged from $50 to $150 per MWh and were less than $100 per MWh in the highest-demand hour. Substantial congestion arose on August 2, which led to volatile prices and wide price dispersion across the Midwest ISO system. However, prices in the highest-demand hours were generally less than $200 per MWh.

Overall, our review of the Summer Peak Load Event led to the findings that the Midwest ISO took appropriate actions to maintain reliability in invoking the emergency procedures. However, these procedures dampened the energy prices during the event. This is a very important finding because the long-term economic signals provided by the markets are substantially affected by the pricing that occurs during shortage events.

In addition, we found that the reserve information provided by balancing authorities to the Midwest ISO was often incomplete or inaccurate. Based on our initial review of this event, we provided several recommendations. In response to these recommendations and the Midwest ISO's own evaluation of the event, the Midwest ISO has taken a number of steps to:

- Clarify its emergency operating procedures and their relationship to shortage pricing provisions that currently exist in the market;
- Develop pricing provisions to prevent the emergency actions from depressing legitimately high prices during shortage conditions; and
- Improve its ability to call for voluntary demand curtailments when and where they are needed to maintain reliability.

These changes improved the performance of the Midwest ISO market during a peak load event that occurred in early 2007. However, substantial additional work still needs to be done to ensure that load reductions needed to avoid shortages can contribute to setting prices at efficiently high levels to ensure that the Midwest ISO markets provide adequate long-term economic price signals. Additionally, continuing to work to expand the demand response capability and its ability to participate directly in the Midwest ISO's markets should be a high priority.

F. Transmission Congestion

One of the most significant benefits of the Midwest ISO energy markets is that they efficiently dispatch generation to manage transmission congestion while providing accurate and transparent price signals.

Congestion costs in the day-ahead and real-time markets were significantly lower in 2006. Total congestion costs were $550 million in 2006 as compared with a total of $800 million for 9 months in 2005. Lower natural gas prices throughout most of the year and lower average peak loads decreased the costs of congestion in 2006. In addition, improved coordination procedures between Midwest ISO and PJM greatly reduced congestion on the path to TVA in 2006. In 2005, non-firm transmission service sold by PJM to TVA generated substantial power flows over the interfaces to TVA. This service was not initially coordinated under the market-to-market provisions, which led to the sharp increase in congestion in the fourth quarter. PJM subsequently took steps to coordinate this service with the Midwest ISO.

Finally, as was the case in 2005, the real-time energy market did not have sufficient capability to redispatch generation to manage the transmission congestion in a number of cases in 2006. The report shows that this is due in part to the inflexible dispatch parameters of certain suppliers. A real-time market parameter that the Midwest ISO uses to identify generators to redispatch when congestion arises also contributed to instances of unmanageable congestion. The report recommends several changes designed to increase redispatch capability, which should improve the efficiency of the market outcomes when the network is congested.

G. Financial Transmission Rights

Financial transmission rights ("FTRs") provide a hedge for congestion because the day-ahead congestion revenue over the path that defines the FTR is paid to the FTR holder. FTRs were fully funded in 2005, but not in 2006. In 2006, insufficient congestion costs were collected to pay the full amount obligated to the FTR holders. This is not uncommon in other markets and occurs when less transmission capability is available in real-time than was assumed in the FTR market. There are a number of reasons, including: a) loop flows occurring that were not fully reflected in the FTR modeling and b) significant transmission outages. Loop flows are the power flows over the Midwest ISO system that are caused by generation and load outside of the Midwest ISO. It effectively reduces the transmission capability available for the Midwest ISO dispatch.

The over-estimate of available transmission capability in the FTR market can happen because the FTR market is operated based on power flow cases performed months in advance. These cases will not accurately capture all operating conditions, so the FTR allocation process and market generally result in some oversubscription of the transmission system as unanticipated outages and loop flows reduce the capability of the system in real time.

Other transmission rights were created to accommodate grandfathered agreements (e.g., Option B FTRs, Carve-Outs, Expanded Congestion Hedges) – payments to these rights were only 4 percent of the total payments. It is good that payouts to non-FTR rights are limited because FTRs provide more efficient incentives than these alternative forms of transmission rights.

The report also evaluates the performance of the FTR auctions by comparing the monthly prices for the FTRs to the actual value of congestion payable to the FTRs. We found that the FTR prices for 2006 were generally consistent with the value of congestion with some notable exceptions. Congestion in the Minnesota area in the fourth quarter of 2006 was not well anticipated in the FTR market, leading to some large discrepancies between the FTR and congestion values. Nonetheless, the pricing of FTRs should continue to improve over time as participants gain experience with the market.

H. External Transactions

The Midwest ISO relies heavily on net imports to serve its load and meet its operating reserve requirements. On average, the Midwest ISO imports almost 4,200 MW in on-peak hours and close to 2,000 MW in off-peak hours. Normally, almost half of these imports enter the Midwest ISO over the Manitoba Hydro interface. Late in 2006, however, poor water conditions led to substantial reductions in the imports over the Manitoba Hydro interface. As discussed above, this led to significant changes in the congestion patterns in the western portions of the Midwest ISO. The Midwest ISO is also a net importer from PJM, although the power flows across this interface also frequently reverse direction.

Our analysis of the interaction between the Midwest ISO and adjacent markets shows that the prices at the border between the markets are relatively well arbitraged. Like other markets, however, the Midwest ISO relies on participants to increase or decrease their net imports to causes prices to converge between the Midwest ISO and adjacent markets. Given the uncertainty regarding the difference in prices (because the transactions are scheduled in advance), one cannot expect perfect convergence. There were a number of hours exhibiting large price differences between the Midwest ISO and adjacent markets that were accompanied by sub-optimal interchange between the markets. In fact, the flows in a number of these hours were scheduled from the high-priced market to the lower-priced market. To achieve better price convergence, we recommend that the RTO's consider expanding the Joint Operating Agreement ("JOA") to optimize the net interchange between PJM and the Midwest ISO.

The report also evaluates the market-to-market coordination under the JOA that the Midwest ISO and PJM use to jointly manage transmission congestion caused by generation in both areas. This process has delivered significant benefits by allowing the two RTOs to work cooperatively to manage congestion. The report recommends a number of refinements and additions to this process that will deliver most of the efficiency benefits of performing a joint dispatch with PJM without the substantial costs of doing so. A number of these recommendations are being actively reviewed by Midwest ISO and PJM working groups. These refinements include optimizing the relief requested by each RTO and changing the calculation of LMPs affected by the market-to-market constraints.

I. Market Power Issues and Mitigation

This report provides an overview of the market concentration and other potential market power indicators, as well as a review of the conduct of participants and imposition of market power mitigation measures in 2006.

Although reliable inferences regarding market power cannot be drawn from market concentration statistics, the report indicates that concentration is low for the overall Midwest ISO area, but quite high in the East, West, and WUMS sub-regions. The top three suppliers control from almost 60 up to 80 percent of the supply in these areas.

A more reliable indicator of potential market power is the indication that a supplier is "pivotal", which means a portion of the load or reserve requirements cannot be satisfied without the resources of the largest supplier. The analysis in the report shows:

- In WUMS, there is a pivotal supplier in more than 65 percent of the hours when load exceeds 60 GW (this represents 63 percent of all hours).
- The West and East regions do not regularly exhibit a pivotal supplier except in hours when load exceeds 80 GW (7.3 percent of all hours).

We also conducted a pivotal supplier analysis by transmission constraint to identify the frequency with which a single supplier's resources are needed to manage a constraint. Approximately 60 percent of the active "broad constrained area" ("BCA") constraints have a pivotal supplier. BCAs are all constraints other than those into and within WUMS. Almost 76 percent of the active "narrow constrained area" ("NCA") constraints have a pivotal supplier. NCAs in 2006 were designated to include the constraints into or within WUMS. BCAs and NCAs are both defined to include all of the generating units that have a significant impact on the power flows over the constrained interface

As a percentage of all intervals during 2006, there was an active BCA constraint with at least one pivotal supplier in two-thirds of the hours and an active NCA constraint with a pivotal supplier in over 35 percent of the hours. Hence, we found substantial local market power associated with both BCA and NCA constraints.

Mitigation measures are applied differently to BCAs and NCAs. 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 cannot be designated in advance. Therefore, BCA constraints are defined dynamically. In the fall of 2006, a new area in Minnesota met the criteria for definition of a NCA due to the changes in congestion patterns describe above. We made a filing to FERC with the Midwest ISO in November 2006 and FERC approved the new NCA in January 2007.

The report shows little evidence of substantial attempts to withhold resources physically or economically to exercise market power. This explains why mitigation was applied infrequently. Energy offers were mitigated for BCA constraints in 14 instances and for NCA constraints in 3 instances. This mitigation occurs pursuant to automated conduct and impact tests that utilize clearly-specified criteria. In addition, offers from suppliers that have market power because their units must be committed to maintain reliability can be mitigated if they are economically withheld. Mitigation of offers that affect RSG payments was also infrequent in 2006. This was due to the fact that suppliers with local market power generally did not attempt to exercise market power.

We continually review the costs associated with RSG payments and can confirm that they were largely incurred when specific reliability issues arose in 2006 that required the commitment of units owned by a single supplier. Therefore, although mitigation was imposed infrequently, it remains a critical component of the market to ensure market prices remain just and reasonable.

J. Summary of Recommendations

In its first full year of operation, the Midwest ISO's markets have performed relatively well. However, the lack of ancillary services markets and other issues discussed in this report indicate a number of opportunities for improvement. Based on our findings in this report, we provide the following recommendations:

1. Develop real-time ancillary services markets as soon as practicable. Ancillary services markets that are jointly optimized with the energy markets will provide two significant benefits:

- More efficient allocation of resources between ancillary services and energy production; and

- Efficient prices for both services to reflect the economic trade-offs between reserves and energy.

2. Implement a "look-ahead" capability to improve the commitment of gas turbines and to better manage ramp capability on slow-ramping units, which should reduce the out-of-merit dispatch quantities and RSG payments.

3. In the longer-run, develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.

   - This change will improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG payments.

   - We have been working with Midwest ISO to develop feasible options for addressing this recommendation.

4. To increase the manageability of transmission constraints, we recommend the Midwest ISO allow generating resources with lower effects on a constraint to be redispatched (i.e., GSFs less than the current 2 percent cutoff).

   - This recommendation had been made previously and work is underway by the Midwest ISO to modify and test its software to implement this recommendation.

5. When a transmission constraint is unmanageable, we recommend the Midwest ISO discontinue its constraint relaxation procedure and use the constraint penalty factor to set the LMPs. This is particularly important for the market-to-market constraints.

6. Regarding the market-to-market process, we recommend the Midwest ISO consider the following changes and work with PJM on these or other changes to improve the performance of the market-to-market process:

   - Adjusting the amount of relief each RTO requests from the other;

   - Instituting a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly;

   - Optimizing the real-time net interchange between the two RTO areas; and

   - Developing a process to coordinate external transactions with non-MISO/PJM areas within the JOA.

7. Regarding intra-hour imports and exports, we recommend the Midwest ISO consider:

   - The feasibility of settling intra-hour transactions on at 15-minute basis; and

- Limiting acceptance of such transactions based on Midwest ISO's available capability to ramp internal generation up or down in support of the transaction.

8. Identify forecasting changes to address the seasonal errors in its day-ahead load forecasting in 2006.

   - The Midwest ISO replaced its day-ahead load forecasting tool in March 2007 to improve its forecasting performance.

9. Improve the management and pricing for demand response programs, including:

   - Developing centrally-coordinated demand response programs; and

   - Allowing the interruptible load and demand response resources to set energy prices in the real-time market when they are called on under shortage conditions.

   - These actions will improve the incentive and opportunity for the development of new demand response, and allow the Midwest ISO to send more efficient long-term economic signals.

   - The Midwest ISO is actively working with the Demand Response Task Force and the States to identify improvements in these areas.

10. Continue work to clarify the capacity requirements contained in Module E of the Midwest ISO tariff and take appropriate steps to enforce these requirements.

    - This will allow a decentralized contract market to develop for satisfying these capacity requirements that will improve the market signals when new resources are needed.

    - As noted above, work us underway on a number of these recommendations and the Midwest ISO is evaluating others. We will be available to consult with the Midwest ISO and its participants in responding to the recommendations. However, we reiterate that even without these improvements, the energy markets introduced by the Midwest ISO in early 2005 have generated substantial benefits for the region.

II. Prices and Revenues

The Midwest ISO completed its first full year of operating competitive wholesale electricity markets in 2006. The markets operated by the Midwest ISO include day-ahead and real-time energy markets that produce locational marginal prices ("LMPs") reflecting the value of transmission congestion throughout the system, and financial transmission rights ("FTRs") that allow participants to hedge congestion between various locations. This report evaluates the outcomes of these markets in 2006. In this first section, we summarize and evaluate prices and revenues in the Midwest ISO markets.

A. Overview of Prices and Fuel Costs

We begin our analysis of the market results with an overview of the electricity prices and fuel prices for the Midwest ISO markets. Our first analysis is shown in the following two figures. Figure 1 shows the average monthly day-ahead energy prices for three of the Midwest ISO pricing hubs and the WUMS area.[3] Significant price differentials between hubs generally reflect transmission congestion, although locational price differences can also be caused by transmission losses. Figure 2 shows the same analysis for the real-time market.

The figures also show the monthly mean natural gas price in each month. As was also the case in 2005, both figures show that changes in fuel prices were a contributor to the fluctuations in electricity prices in 2006, particularly later in the year. Natural gas prices decreased initially from the extremely high prices that prevailed in late 2005. The correlation of energy prices with gas prices is expected because fuel costs represent the majority of most generators' marginal production costs. In a competitive market, generators have incentives to offer their energy at its marginal cost. Hence, as fuel costs rise, generators' offer prices should rise. Although only about 28 percent of the capacity in the Midwest ISO region is fired by natural gas, gas units are on the margin in most peak load hours. Therefore, the correlation of natural gas prices and electricity prices indicates that the markets are performing efficiently.

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

Figure 1: Day-Ahead Average Monthly Hub Prices
2006: All Hours

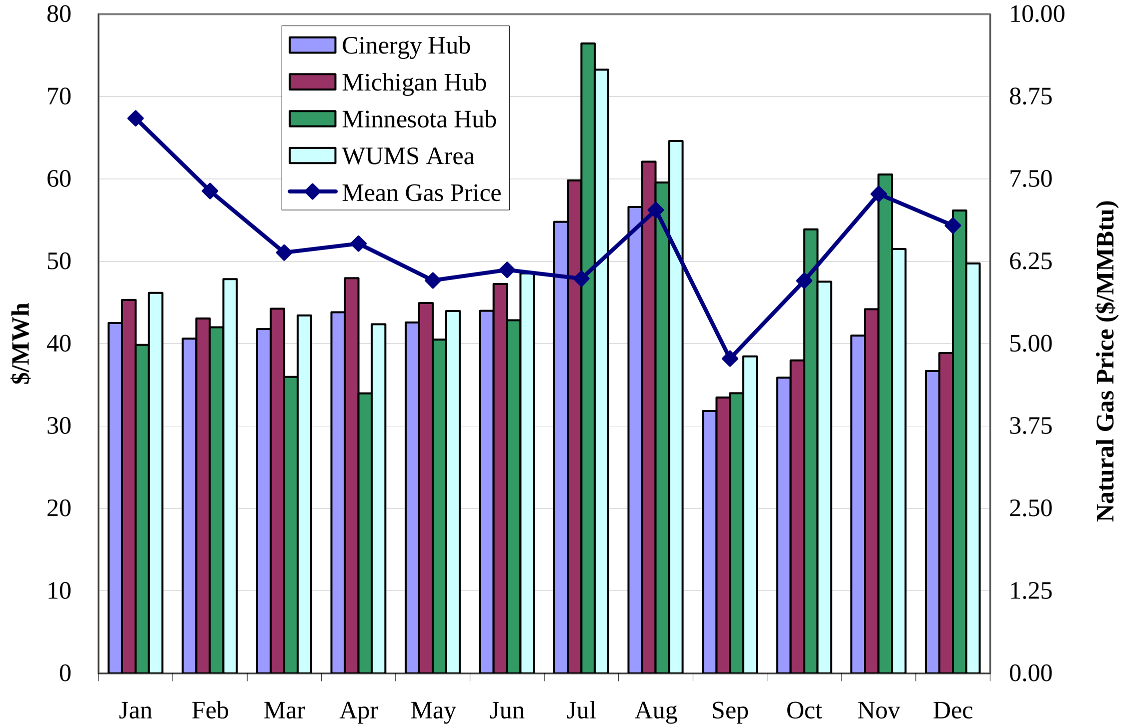
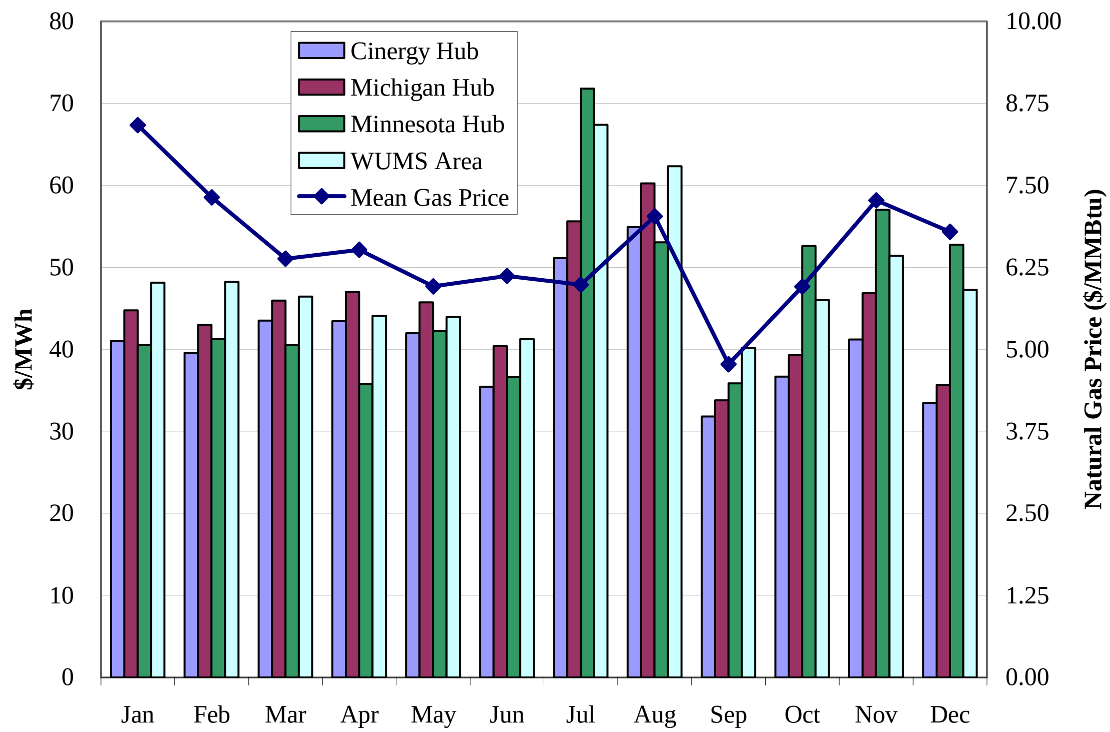


Figure 2: Real-Time Average Monthly Hub Prices
2006, All Hours



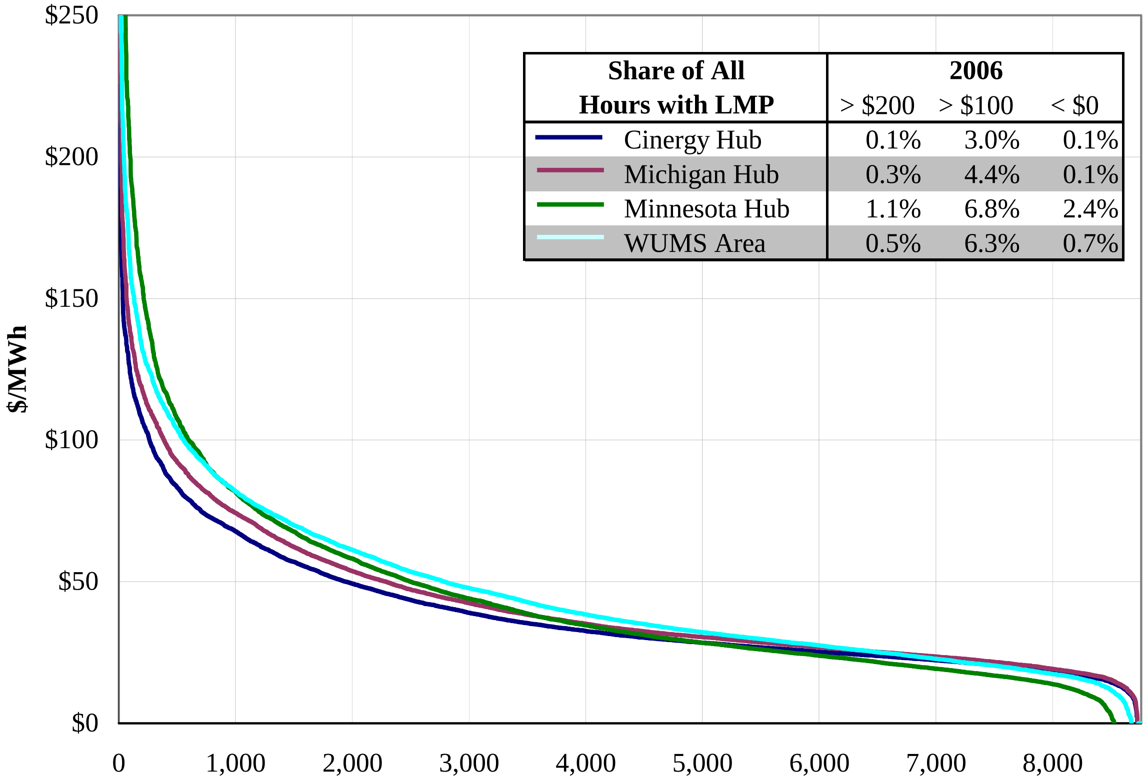
The price differences between the hubs in these figures also show the transmission congestion in the Midwest ISO area. The most significant price differences in the first quarter was into and within WUMS because the most frequently binding transmission constraints were those that limit imports into the WUMS and North WUMS areas from the western and southern directions. Over the entire year, WUMS remained the highest-priced hub. However, the congestion into WUMS was less frequent and severe than it was in 2005.

In the late spring, generator outages in Michigan resulted in higher imports and congestion into Michigan. Due to generator and transmission outages, the highest prices were in Minnesota due to congestion from the south. Sharply reduced imports over the Manitoba interface in the last three months of the year contributed to congestion caused Minnesota to be the highest-priced hub.

In November, the Midwest ISO filed for approval of the Minnesota NCA, and FERC approved the application on January 19, 2007. The area designated as an NCA includes portions of Minnesota, Iowa, and Wisconsin. The area is defined by a set of constraints that limit imports from south to north into Minnesota.

Our next analysis evaluates the hourly prices in the real-time market. Figure 3 shows real-time price duration curves for four locations in the Midwest ISO region. A price duration curve shows the number of hours (x-axis) when the LMP is greater than or equal to a particular price level (y-axis). For example, the curve for the Cinergy hub crosses the $65 per MWh level at approximately the 1000-hour level on the x-axis. Therefore, in approximately 1000 hours during 2006, the Cinergy hub price exceeded $65 per MWh.

Figure 3: Real-Time Price Duration Curve
2006: All Hours



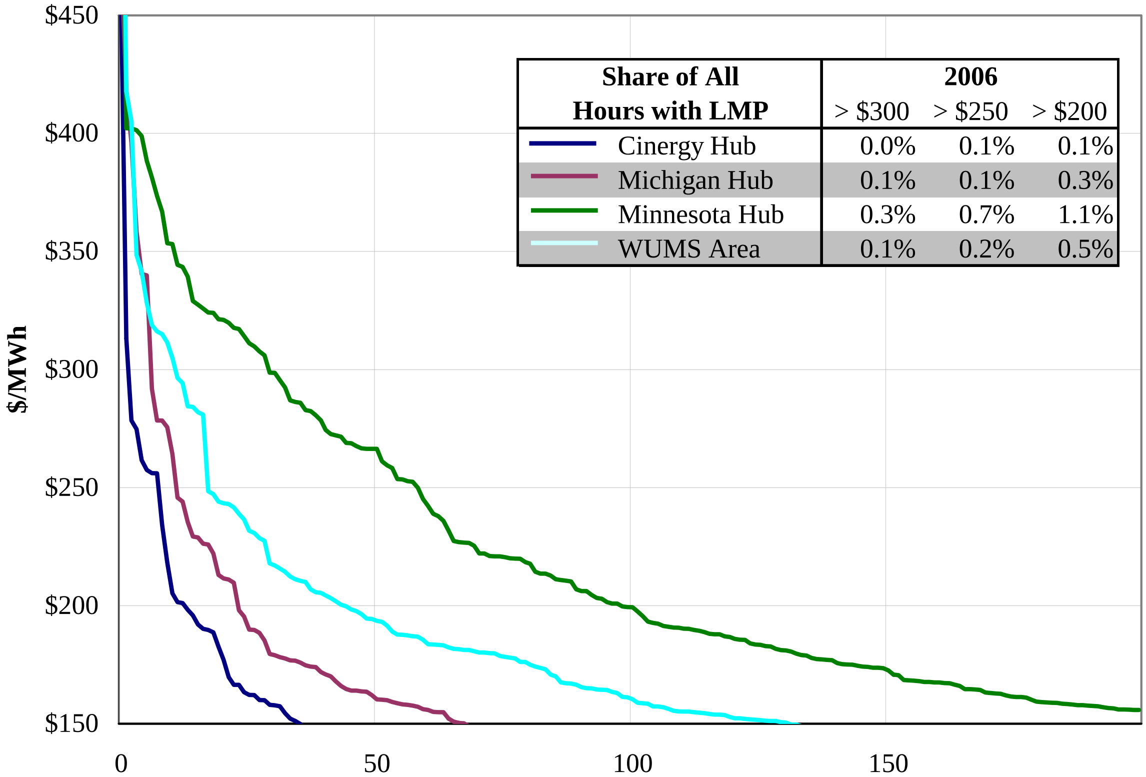
The differences between these curves are due to congestion and losses that cause prices to vary by location. While prices in WUMS are higher on average, the Minnesota hub actually had more high-priced hours than WUMS. The Minnesota hub had 1.1 percent of hours above $200 per MWH and 6.8 percent of hours above $100 per MWH. Minnesota also had by far more hours with negative prices, 2.4 percent, than any other region. In general, these negative prices occur when the Midwest ISO has difficulty managing the congestion into WUMS due to:

- Limited flexibility in dispatching imports from Manitoba,
- Limited control of power scheduled over certain DC lines, and
- Dispatch inflexibility of certain baseload generation in Minnesota.

WUMS experienced less congestion in 2006 than in 2005, with 0.5 and 6.3 percent of hours in 2006 exceeding $200 and $100 per MWh, respectively. Michigan is the next highest-priced region with 0.3 and 4.4 percent hours above $200 and $100 per MWh, respectively. Congestion into Michigan also often requires the supplemental commitment of gas resources by the Midwest ISO to maintain reliability in that area.

In Figure 4, more detail is provided on the highest prices that occurred in real-time during 2006. Prices in these peak hours play a critical role in sending the economic signals that govern investment and retirement of generation. As shown in the figure, prices in Minnesota and WUMS are generally higher in these hours than the prices at other locations in the Midwest ISO. The chart shows that Minnesota actually has the most high-priced hours, followed by WUMS and Michigan. Prices throughout the Midwest ISO were above $300 in a very small number of hours – ranging from two (0.0%) at Cinergy to 29 hours (0.3%) at the Minnesota Hub.

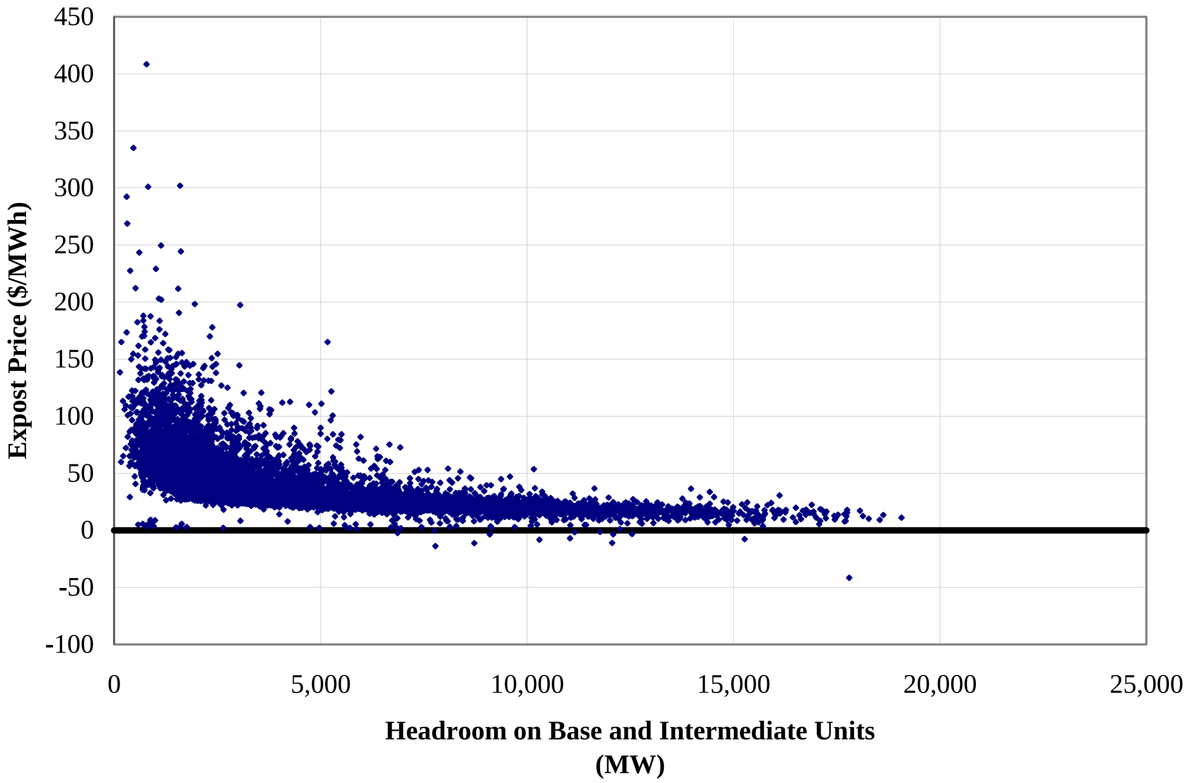
Figure 4: Real-Time Price Duration Curve
2006: High Price Hours



The low frequency and magnitude of peak pricing events in the Midwest ISO in 2006 will contribute to long-run economic signals that are unlikely to result in substantial new investment. These long-run economic signals are evaluated in detail later in this section of the report. Based on the results of this evaluation, we recommend several improvements to address these price signals and the adequacy of supply and demand resources in the Midwest ISO.

Our next analysis examines the relationship between prices and the dispatchable capacity remaining on committed units (i.e., generators that are online). We refer to this undispatched capacity as "headroom". More precisely, we define headroom as the dispatch range between a generator's current output level and its maximum output level ("EcoMax"). Headroom generally declines as demand increases and the market accepts higher-priced offers from online resources. Hence, headroom and prices should be negatively correlated in a well-functioning market. To determine whether this has been true of the Midwest ISO energy markets during its first year of operation, Figure 5 shows the relationship between headroom on baseload and intermediate generating resources in the real-time market.

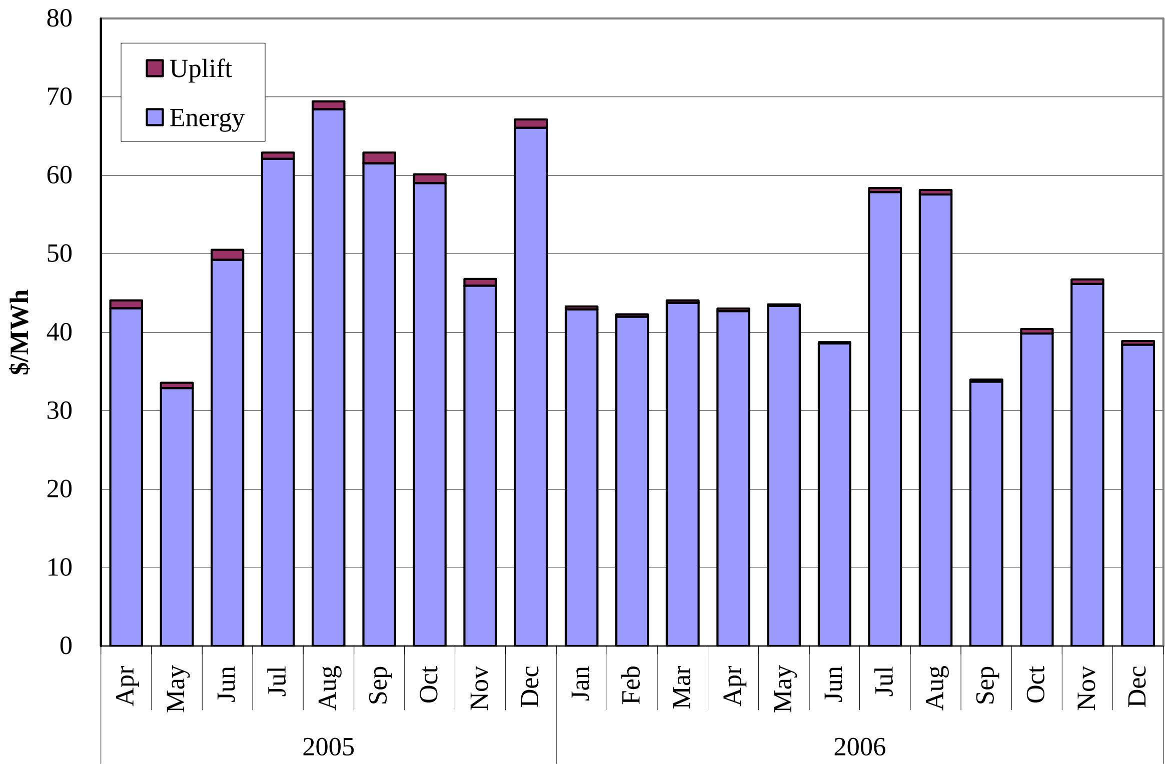
Figure 5: Relationship of Base & Intermediate Headroom to Price
Real-Time Market: All hours



This figure shows that the market is functioning as expected, with headroom strongly and negatively correlated with prices. While the price-headroom relationship is very strong, the relationship indicates some variance, especially in high-priced hours. Variance in this relationship can occur for at least four reasons. First, ramp limitations on a 5-minute basis can prevent headroom from being accessible in the short-term, leading to higher prices. Second, prices can be high in constrained areas even when headroom is substantial. Third, since this figure shows prices over the entire study period, substantial changes in fuel prices during the period can cause different prices to prevail at different times of the year in hours exhibiting the same level of headroom. Lastly, economic withholding can cause higher prices than one would predict given the level of prevailing headroom. This final issue is examined in detail later in this report, where we find that economic withholding has not been a significant problem in 2006.

Next, we analyze the "all-in" price of wholesale power. The all-in price includes the costs of energy and real-time revenue sufficiency guarantee ("RSG") costs. This metric is intended to show the total cost of serving load from the Midwest ISO energy markets. The all-in price does not include ancillary services and capacity costs since the Midwest ISO currently lacks these markets.[4] Figure 6 shows the all-in price of the Midwest ISO markets in 2005 and 2006.

Figure 6: All-In-Price of Wholesale Electricity
2005 - 2006



[4] Ancillary service markets are currently expected to be operational in the spring of 2008.

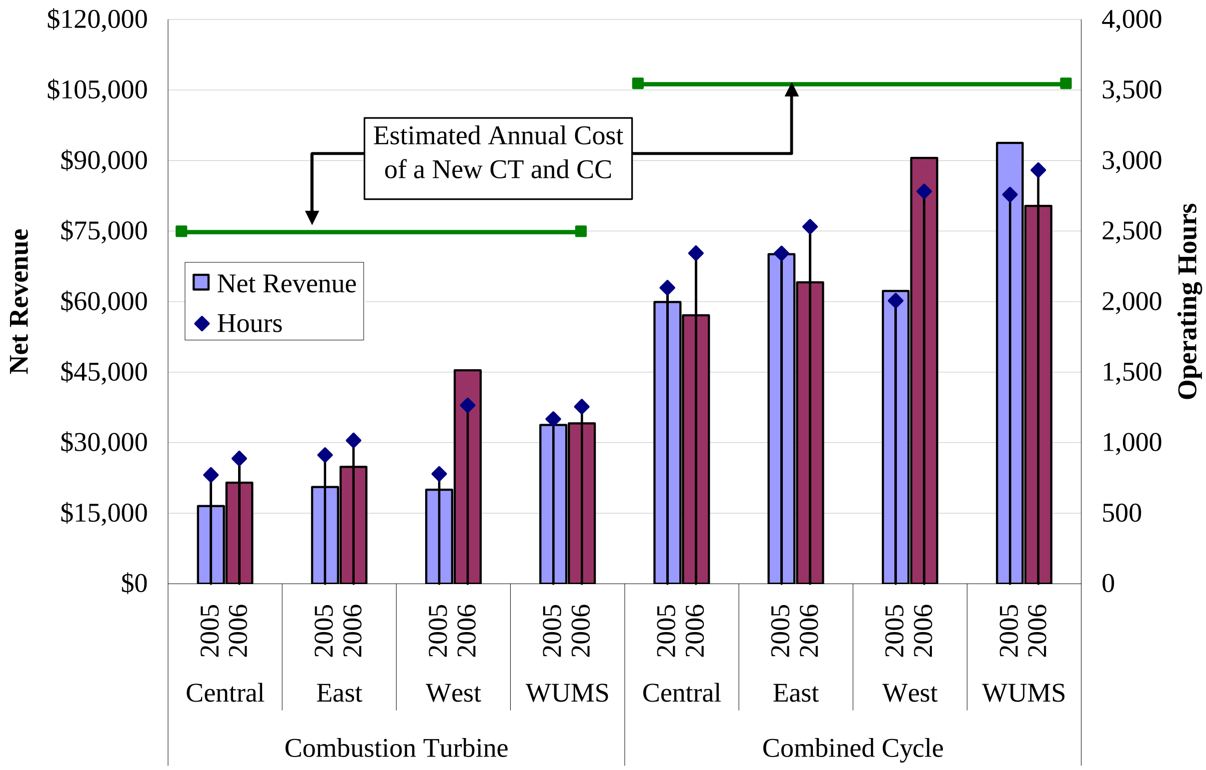
The all-in price declined in 2006 to $45 per MWh compared to $56.16 per MWh in 2005. As in 2005, the 2006 all-in price peaked during the highest load months of the summer. The analysis also shows that RSG costs were a small share of the all-in price in both 2005 and 2006, decreasing from less than 2 percent to less than 1 percent of the average all-in price from 2005 to 2006. While this subsection provided a summary of the prices that occurred in the Midwest ISO energy markets during 2006, the next subsection evaluates the economic signals that these prices send to market participants.

B. Net Revenue Analysis

The economic signals provided by the Midwest ISO markets can be evaluated using the "net revenue" metric. 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 when it is not economic. A well-designed market should produce net revenues sufficient to finance new investment when demands on the system for energy and reserves begin to exceed resource availability. Even if the system is in long run balance, 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 earned would include revenues from capacity and ancillary service markets in addition to those earned in the energy markets. These are not included in our analysis for the Midwest ISO because the Midwest ISO markets did not include capacity or ancillary services markets in 2006.

The analysis incorporates FERC's standardized assumptions for calculating net revenues 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. Because net revenues depend on the cost of production, the analysis depends on the type of unit considered. As is standard in RTO market analysis, we analyze the net revenue for two types of new units: a gas combined-cycle (heat rate assumed of 7000 BTU/KWh) and gas combustion turbine (heat rate assumed of 10500 BTU/KWh). The net revenue results for these two types of units are shown in Figure 7 together with the number of hours each type of unit would be estimated to run.

Figure 7: Net Revenue and Operating Hours
2005 – 2006



Because they have substantially lower production costs than simple-cycle combustion turbines, combined cycle generators run more frequently (over 25 percent of all hours in 2006, over 30 percent in WUMS and the West). Hence, a new combined cycle generator would receive higher net revenues, which ranged locationally from more than $50,000 to $90,000 per MW-year. The net revenues for combustion turbines in 2006 ranged from $20,000 to $45,000. We estimated that combustion turbines would be expected to run in less than 15 percent of the hours.

Based on a review of the actual operating statistics of existing combustion turbines and combined cycle generating units, we found that the estimated run hours are consistent with the actual operating experience of gas-fired generators in the Midwest ISO region in 2006. Run hours for an efficient combustion turbine were slightly higher in the West and WUMS (roughly 18%) and slightly lower in the East region (8%); whereas, combined cycle run hours were higher on average than predicted by the net revenue calculation. Actual combined cycle run hours deviate from the net revenue estimates more than combustion turbine hours do because most combined cycles have at least a four-hour minimum runtime, and minimum runtime is not considered in the net revenue calculation.

Compared to 2005, the net revenues in 2006 were slightly higher in most regions for a combustion turbine. Due to the increase in congestion into the West, the net revenue for a combustion turbine in the West more than doubled in 2006 ($45,000 as compared to $20,000 per MW). For combined cycle units, the net revenues were slightly lower in 2006 than in 2005 in all of the regions except the West. In the West region, the net revenues rose from $62,000 to $90,000 per MW.

To determine whether these net revenue levels would support investment in new resources, the figure also shows the annualized cost of a new unit (i.e., the annual net revenue a new unit would need to earn to make the investment economic). The net revenue analysis shows that even in the highest-priced regions (WUMS and West), neither a CT nor CC unit would have earned net revenues sufficient to justify new investment. 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 2006 were unexpectedly low, neither of which is true. This outcome is a concern because the report also shows that actual capacity margins relative to forecasted peak demand for 2007 are very low throughout the Midwest ISO.

The fact that net revenues are not currently sufficient to support new entry is due in part to the Midwest ISO markets remaining incomplete. In particular:

- Net revenue high enough to support new entry requires either a significant number of price spikes associated with reserve shortages or capacity market revenues – the Midwest ISO had neither in 2006.
- The Midwest ISO currently lacks ancillary service revenues, which can provide substantial net revenue for resources such as combustion turbines that are called upon to produce energy in only a small share of the 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. Ancillary services markets can contribute to the provision of efficient long-term signals. In February 2007, Midwest ISO filed for FERC approval of ancillary service markets for Regulating Reserves and Contingency Reserves. Such markets would allow the Midwest ISO's markets to more fully reflect the reliability requirements of the region and will ensure that the region's energy prices reflect the trade-offs that must be made between operating reserves and energy when the system is in shortage. The development of these markets should be among the Midwest ISO's highest priorities.

Additionally, the Midwest ISO's tariff includes certain capacity requirements in Module E. This Module requires that load-serving entities designate network resources sufficient to cover their peak load, plus a specified margin. However, the specification of what types of resources and/or firm contracts will satisfy these requirements are unclear and there is very little enforcement authority currently in the Tariff. If these requirements were clear and well enforced, it would allow a decentralized contract market to develop to satisfy these capacity requirements that would improve the market signals when new resources are needed. Hence, we support the work the Midwest ISO is currently doing with its participants and the States to make improvements in these areas. These changes will help assure the adequacy of resources in the Midwest ISO.

III. Load and Resources

Understanding basic supply and demand conditions in the Midwest provides the foundation for a more detailed understanding of the Midwest ISO markets. In this section, 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, including the balancing authorities that operate the control areas in the Midwest ISO region. There are over 60 owners of generation resources in the Midwest ISO footprint as defined by the set of Midwest ISO control areas. This group includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers. Generation owned by non-transmission owners (e.g., municipal utilities, independent power producers) are included as part of the control area to which their generation is interconnected for purposes of calculating the load and generation statistics in this section.

For our analysis, we generally divide the Midwest ISO region into four sub-regions based on the operating areas the Midwest ISO uses to operate the system:

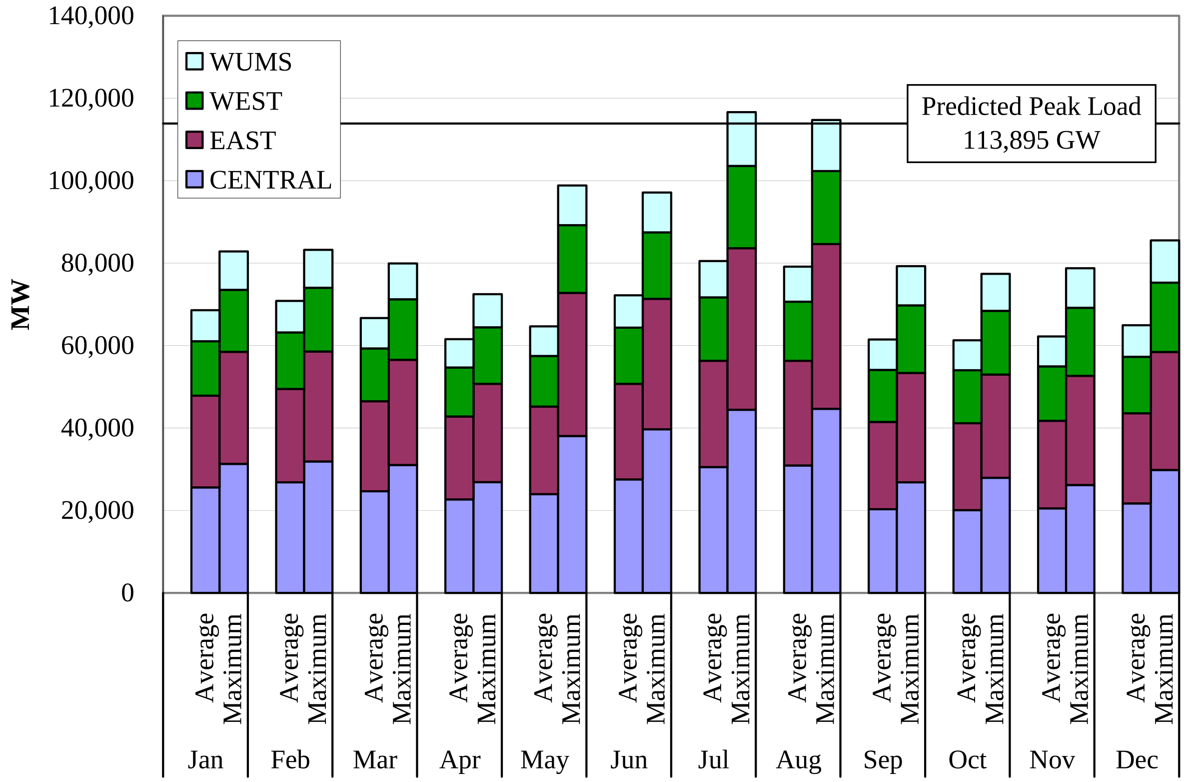
- East – generally includes the Midwest ISO control areas that had been located in the NERC ECAR region;
- West – generally includes the Midwest ISO control areas that had been located in the NERC MAPP region;
- Central – generally includes the Midwest ISO control areas that had been located in the NERC MAIN region, but excluding MAIN utilities located in the Wisconsin-Upper Michigan System ("WUMS"); and
- WUMS -- the Midwest ISO control areas located in the WUMS region.

It should be emphasized that these four sub-regions should not be viewed as distinct geographic markets. This point is particularly important for the data presented below concerning market concentration in these sub-regions. Market concentration in these sub-regions does not allow one to draw reliable competitive conclusions. An accurate market power analysis would require investigations beyond calculating market share and concentration statistics.

A. Load and Production

We begin our analyses in this section by showing the Midwest ISO monthly peak load and average load by sub-region in Figure 8.

Figure 8: Monthly Maximum and Average Load
2006

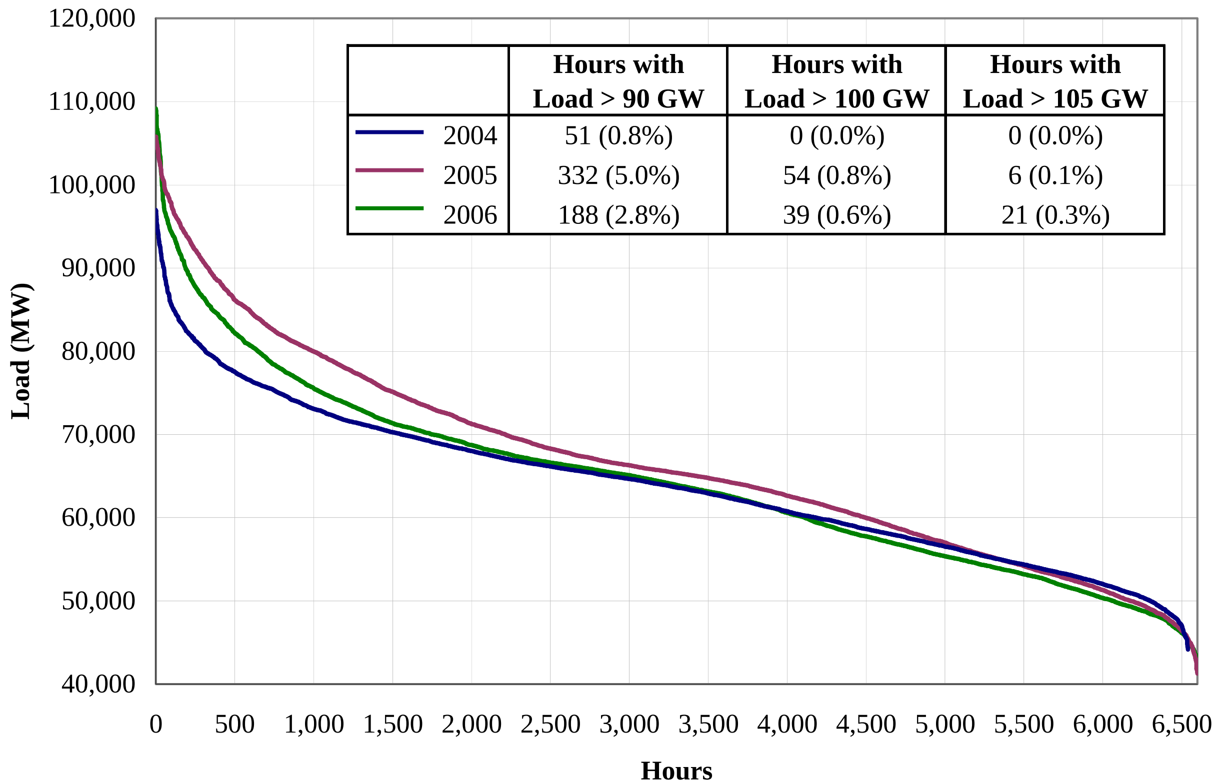


The figure shows that most of the load in the Midwest ISO is in the Central and East sub-regions. The figure also shows that the Midwest ISO is a summer peaking region. In July and August, the peak load was 116.3 GW and 114 GW, respectively. These monthly peaks were above the predicted peak load for 2006 of 113.9 GW, which is shown 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 44 percent higher than the average loads. Because electricity cannot be stored, the market relies on intermediate and peaking resources to meet these demands.

The next analysis shows hourly load duration curves for 2004, 2005, and 2006. A load duration curve is a relationship showing number of hours (horizontal axis) in which load is greater than an indicated level (vertical axis). These are constructed similarly to the price duration curves shown in the prior section of the report. This analysis is shown in Figure 9. To make the data for each year comparable, it includes only the hours from April to December in each year and LGEE system load is removed from MISO market load.

Figure 9: Load Duration Curves
2004 - 2006



	Hours with Load > 90 GW	Hours with Load > 100 GW	Hours with Load > 105 GW
2004	51 (0.8%)	0 (0.0%)	0 (0.0%)
2005	332 (5.0%)	54 (0.8%)	6 (0.1%)
2006	188 (2.8%)	39 (0.6%)	21 (0.3%)

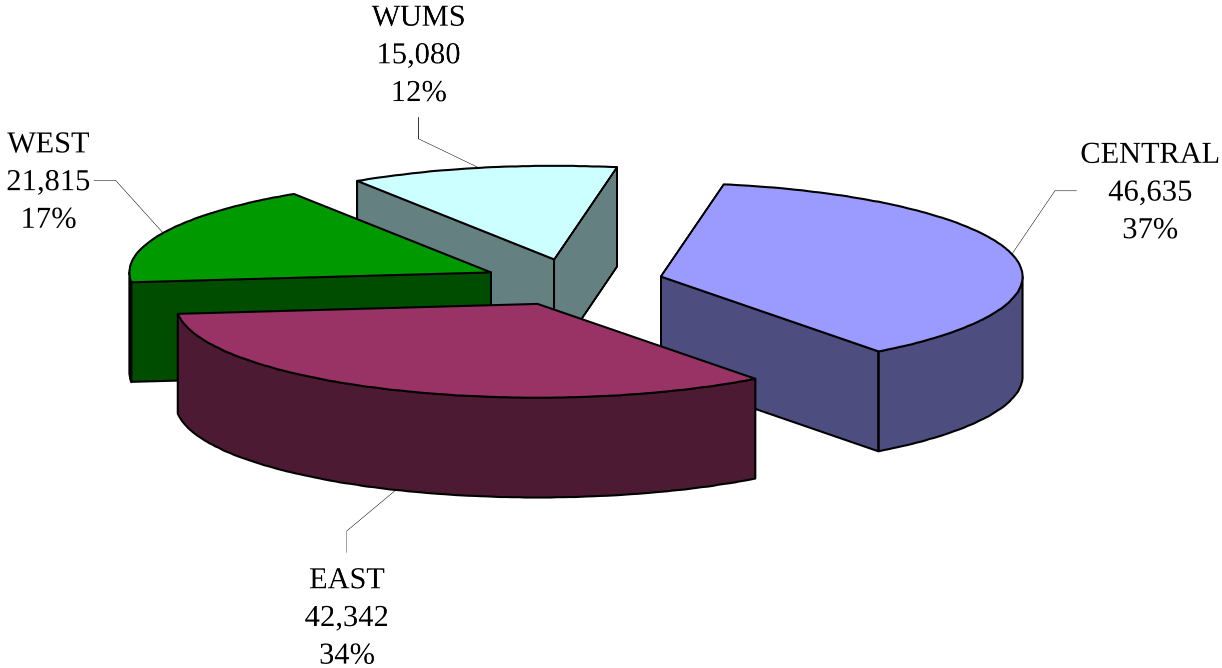
Figure 9 shows that in 2006 there were more hours with extreme demand levels than in prior years. In particular, there were 21 hours when actual loads exceeded 105 GW in 2006 versus 6 hours in 2005 and none in 2004. Although the peak was higher in 2006, average load in 2005 was generally higher than in 2006. There were 188 hours when actual loads exceeded 90 GW in 2006 versus 332 hours (77 percent increase) in 2005. These results stress the importance of efficient pricing during the highest load conditions. More than 25 percent of the resources are needed to meet the energy and operating reserve requirements of the region in the highest 5 percent of load hours.

While 2006 had more extreme loads hours (hours above 105 GW), the peak load levels (e.g., the top 2000 hours) were generally higher in 2005 than in 2006 due to the unusually hot weather in 2005.

B. Generation Capacity

Generating resources in the Midwest ISO market footprint totaled 130 GW in 2006. Figure 10 shows the distribution of this capacity by coordination region.

Figure 10: Generation Capacity by Coordination Region



The capacity in the figure includes only capacity owned by the Midwest ISO market participants, and excludes the Midwest ISO reliability-only members (e.g. NPPD, OPPD). Including the resources of the reliability-only members, the total generating capacity would increase to 170 GW. The total capacity values are reduced from 2005levels due to the departure of LG&E from MISO.

WUMS is actually part of the East coordination region. Because it is a highly congested area, we show WUMS separately from the rest of the East. Consistent with the location of the load in the Midwest, Figure 10 shows that more than 70 percent of the generating capacity is located in the East and Central sub-regions. Our next analysis shows the distribution of generating capacity by fuel type.

Figure 11: Distribution of Generation Capacity by Region
By Fuel Type

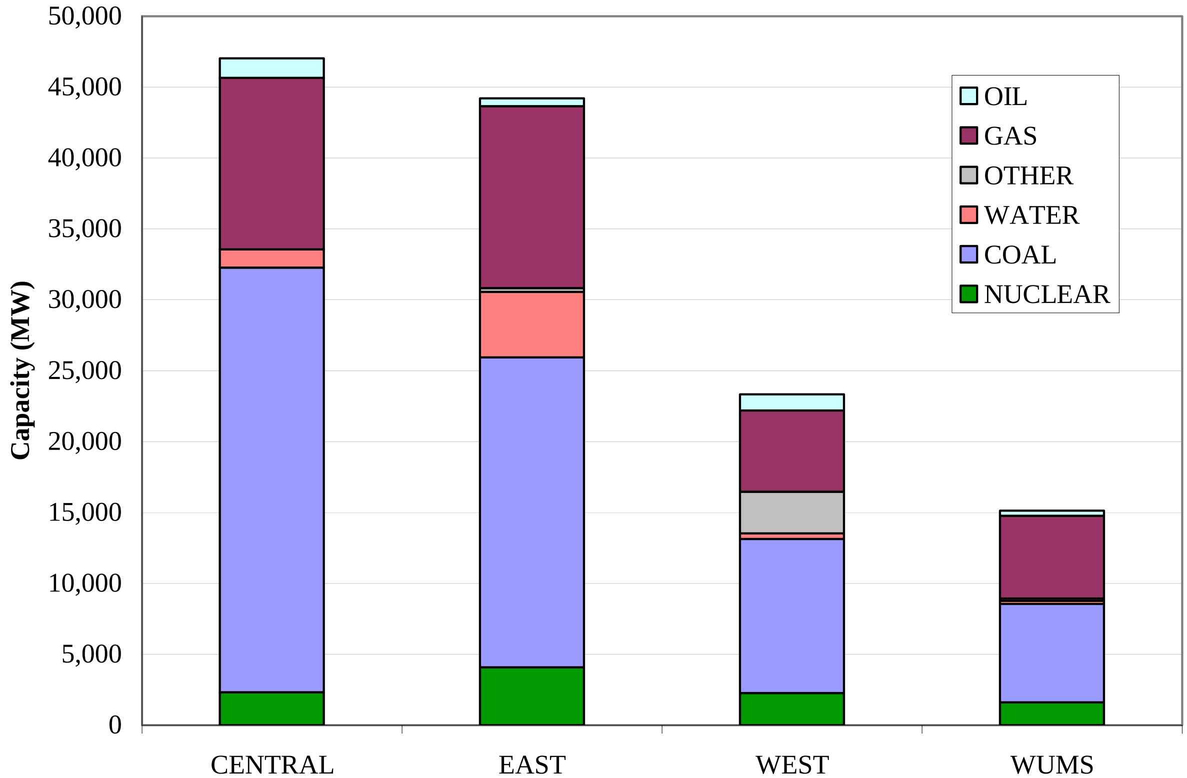


Figure 11 shows that the Midwest ISO relies heavily on coal-fired generating resources. Approximately 55 percent of its generation capacity is coal-fired. Because coal units generally serve as baseload generation, coal-fired resources produce an even larger proportion (78 percent) of total energy generated because they generally have relatively low cost and operate in a high portion of the hours.

The next largest category of capacity is natural gas-fired capacity, which represents about 30 percent of the generating resources in the Midwest. Because natural gas-fired resources have higher costs than most of the other resources in the Midwest, they produce only about 8 percent of the energy in the region. Nevertheless, they frequently set the price in the Midwest ISO markets.

Nuclear plants provide approximately 8 percent of the capacity, while oil and hydro plants represent approximately 2.7 percent and 5 percent respectively. Other units, including wind, provide about 2 percent of capacity. The figure also shows that the mix of generation is relatively homogeneous across the sub-regions. However, the west sub-region hosts most of the wind resources, while the east has the largest quantity of nuclear resources.

C. Resource Margins and Capacity Availability

The peak load in each sub-region must be satisfied by a combination of generating resources within the region and imports. In order to evaluate the adequacy of resources in the region, it is instructive to evaluate the resource margin for each sub-region. To do this, we calculate the ratio of the generation and net firm imports to the peak load for each sub-region. Table 1 summarizes this analysis for 2006, showing each sub-region's:

- generation capacity,
- net firm imports,
- peak internal load,
- peak internal demand, and
- resource margin.

Using these data, we calculated the reserve margin for each region, which is equal to:

(Capacity plus Firm Imports) ÷ (Internal Load or Internal Demand) – 1

Internal demand is internal load less the sum of behind the meter generation, interruptible load and other demand-side response capability.[5] Hence, the table shows the reserve margins when one includes and excludes the interruptible demand and behind the meter generation. The resource margins presented here are broad indicators of the adequacy of the resources in the Midwest ISO region and help to identify potential areas of concern.

5 To the extent demand-side resources have been deployed during peak periods, they would be reflected in lower peak demand (resulting in a higher resource margin). To the extent demand-side resources were available but not deployed during peak periods, the resource margins may be slightly underestimated because the ability to respond to peak load conditions is higher than indicated.

The peak period in 2006 showed that the maximum capacity levels that planners normally assume tend to be overly optimistic. In particular, capacity levels during high temperature events are significantly lower than nameplate capacity suggests, leading to lower than expected reserve margins. Many resources during peak load events must be derated in response to environmental restrictions or due to effect of high ambient temperatures on the performance and capability of the resources. Additionally, intermittent resources cannot be relied on to provide energy during shortage events. Lastly, units are often "permanently derated" by a small amount, meaning that they cannot physically operate at their nameplate capacity level even under ideal circumstances. Table 1 shows the effect of these various deratings on the reserve margins in the Midwest ISO.

Table 1: Resources and Load in the Midwest in 2006

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	38,942	2,521	42,342	15.2%	41,185	12.2%	38,824	6.2%
Internal Demand	36,228	2,521	42,342	23.8%	41,185	20.6%	38,824	14.1%
Central								
Internal Load	38,713	(66)	46,635	20.3%	44,354	14.4%	41,144	6.1%
Internal Demand	37,404	(66)	46,635	24.5%	44,354	18.4%	41,144	9.8%
West								
Internal Load	18,874	2,494	21,815	28.8%	20,167	20.1%	18,468	11.1%
Internal Demand	17,659	2,494	21,815	37.7%	20,167	28.3%	18,468	18.7%
WUMS								
Internal Load	13,581	1,265	15,080	20.4%	14,772	18.1%	13,962	12.1%
Internal Demand	12,547	1,265	15,080	30.3%	14,772	27.8%	13,962	21.4%
MISO								
Internal Load	110,110	6,118	125,872	19.9%	120,478	15.0%	112,398	7.6%
Internal Demand	103,838	6,118	125,872	27.1%	120,478	21.9%	112,398	14.1%

[1] Available Capacity is calculated as the minimum of nameplate capacity and the 99th percentile of capacity offered in the Day-Ahead market.
[2] High Temperature capacity is the maximum offered capacity on August 1, 2006 for units available in the Day-Ahead market. Intermittent units are included at 20% of nameplate. Units unavailable on August 1st are included at Available Capacity.
[3] Net Internal Demand is internal load less behind-the-meter load and demand-side management.

The table shows that reserve margins in 2006 are highly sensitive to the assumed maximum capacity levels and whether interruptible demand is included. Using nameplate capacity levels, the reserve margin for the MISO region is 20 percent based on internal load and 27 percent based on internal demand. Regionally, the reserve margin varies from 15 percent to 29 percent based on internal load and from 24 percent to 38 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 permanent derates and the temperature sensitive capacity that was not available under peak demand conditions, we find that the reserve margin for the MISO region was 7.6 percent based on internal load and 14 percent based on internal demand. Regionally, this reserve margin varied from 6 percent to 12 percent based on internal load and from 10 percent to 21 percent based on internal demand. These results would lead one to conclude that conditions are relatively tight, given an average forced outage rate of 5 percent and a 3 percent operating reserve requirement that must be satisfied in real-time. Given that load continues to grow from year-to-year, these reserve margins should decrease over time. The projected reserve margins for 2007 are shown later in this section.

Table 2 shows the new additions and retirements of capacity that occurred in 2006. The table shows that very little new capacity entered the market in 2006 and even less was retired, resulting in a net addition of little more than 100 MW. This finding is consistent with the results of the net revenue analysis presented in the previous section.

Table 2: Additions and Retirements

Region	Additions	Retirements	Net Change
Central*	0	46	-46
East	0	0	0
West	148	0	148
WUMS	12	7	5
Total	160	53	108

* Excludes LGEE units.

Given that projected load growth outpaces these net additions, we estimate that the reserve margins in 2007 will be lower than in 2006. Table 3 projects reserve margins for the summer of 2007 using generation from the Midwest ISO in March 2007 and load projected by the Midwest ISO in its Summer Assessment for 2007.

Table 3: Resources and Load in the Midwest – Summer 2007

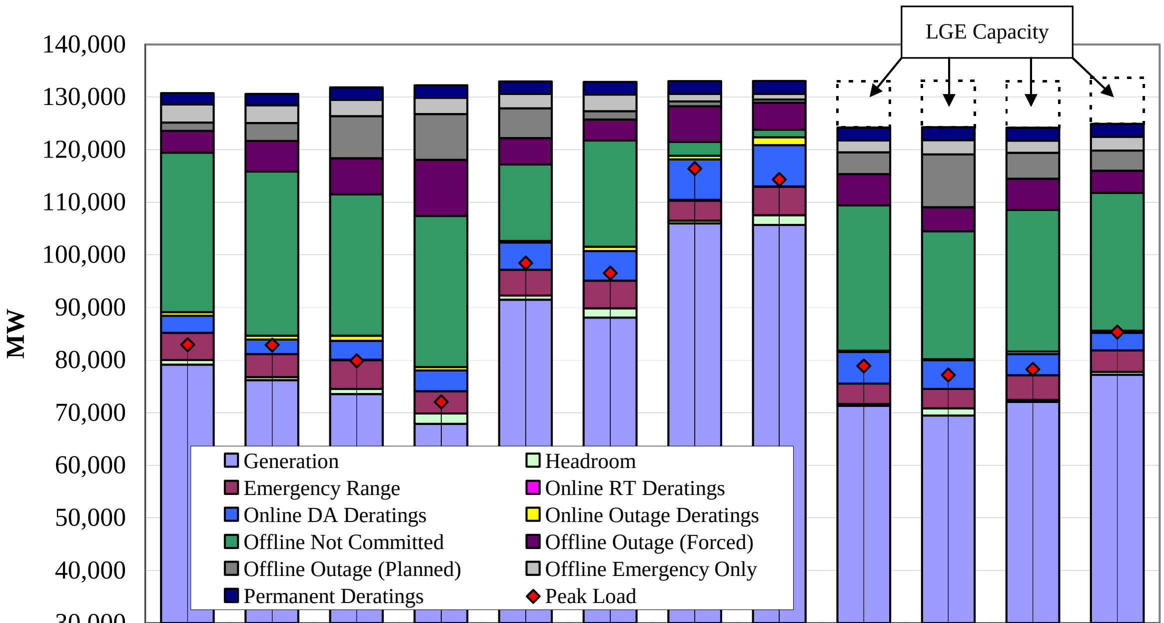
Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temperature Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin
East								
Internal Load	39,380	2,835	42,342	14.7%	41,185	11.8%	38,824	5.8%
Internal Demand[3]	36,712	2,835	42,342	23.1%	41,185	19.9%	38,824	13.5%
Central								
Internal Load	39,594	(36)	46,635	17.7%	44,354	11.9%	41,144	3.8%
Internal Demand	38,045	(36)	46,635	22.5%	44,354	16.5%	41,144	8.1%
West								
Internal Load	20,676	3,113	21,815	20.6%	20,167	12.6%	18,468	4.4%
Internal Demand	18,630	3,113	21,815	33.8%	20,167	25.0%	18,468	15.8%
WUMS								
Internal Load	13,548	1,259	14,970	19.8%	14,662	17.5%	13,862	11.6%
Internal Demand	12,497	1,259	14,970	29.9%	14,662	27.4%	13,862	21.0%
MISO								
Internal Load	113,199	7,080	125,762	17.4%	120,368	12.6%	112,298	5.5%
Internal Demand	105,885	7,080	125,762	25.5%	120,368	20.4%	112,298	12.7%

[1] Available Capacity is calculated as the minimum of nameplate capacity and the 99th percentile of capacity offered in the Day-Ahead market.
[2] High Temperature capacity is the maximum offered capacity on August 1, 2006 for units available in the Day-Ahead market. Intermittent units are included at 20% of nameplate. Units unavailable on August 1st are included at Available Capacity.
[3] Net Internal Demand is internal load less behind-the-meter load and demand-side management.

This table shows that because the load is growing more quickly than the supply in the Midwest ISO region, reserve margins across all regions and MISO as a whole are expected to be tighter in 2007 than in 2006. For example, the reserve margins based on load (excluding interruptible demand) decreases to 5.5 percent. The relatively low reserve margins in 2006 and 2007 affirm the importance of the market sending efficient economic signals for new investment in generation and demand-side response resources needed to maintain reliability under peak conditions.

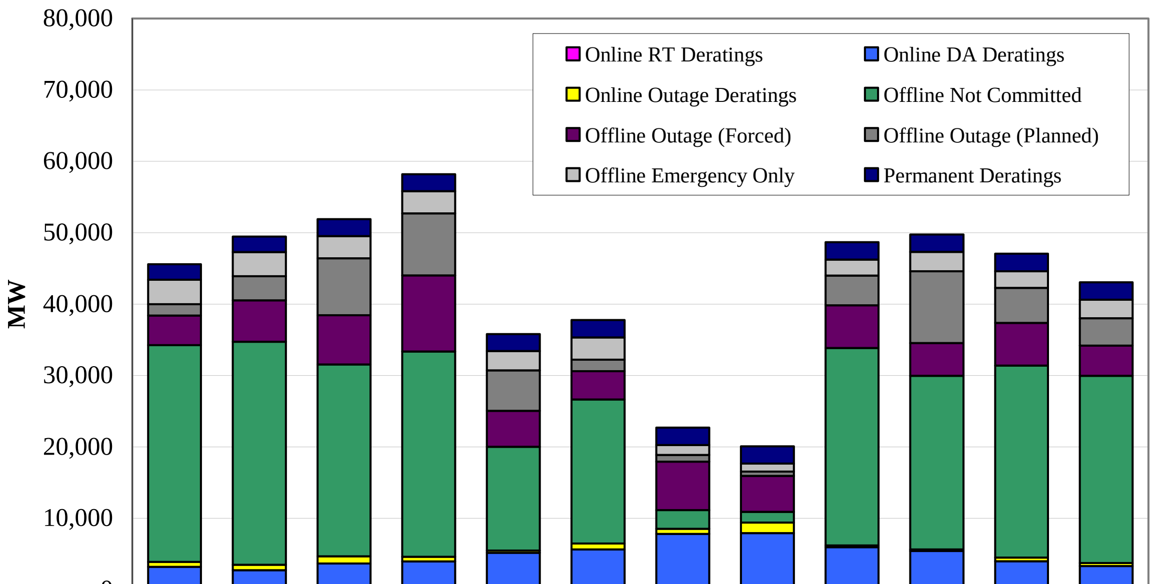
The next analysis, which is shown in Figures 12 and 13, further evaluates reserve margins and capacity availability throughout the year. Figure 12 shows the generation capacity available and unavailable to the market during the peak load hour of each month during 2006. Figure 13 provides the same results but shows only the capacity that was unavailable.

Figure 12: Capacity during Peak Load Hours



Peak Hour	6 PM	7 PM	7 PM	7 AM	2 PM	1 PM	2 PM	3 PM	3 PM	7 PM	6 PM	6 PM
Peak Date	Jan 5	Feb 20	Mar 21	Apr 4	May 30	Jun 22	Jul 31	Aug 1	Sep 7	Oct 3	Nov 30	Dec 7
Peak Load	82,909	82,852	79,862	72,063	98,466	96,518	116,382	114,340	78,885	77,141	78,218	85,333

Figure 13: Offline and Unavailable Capacity during Peak Load Hours



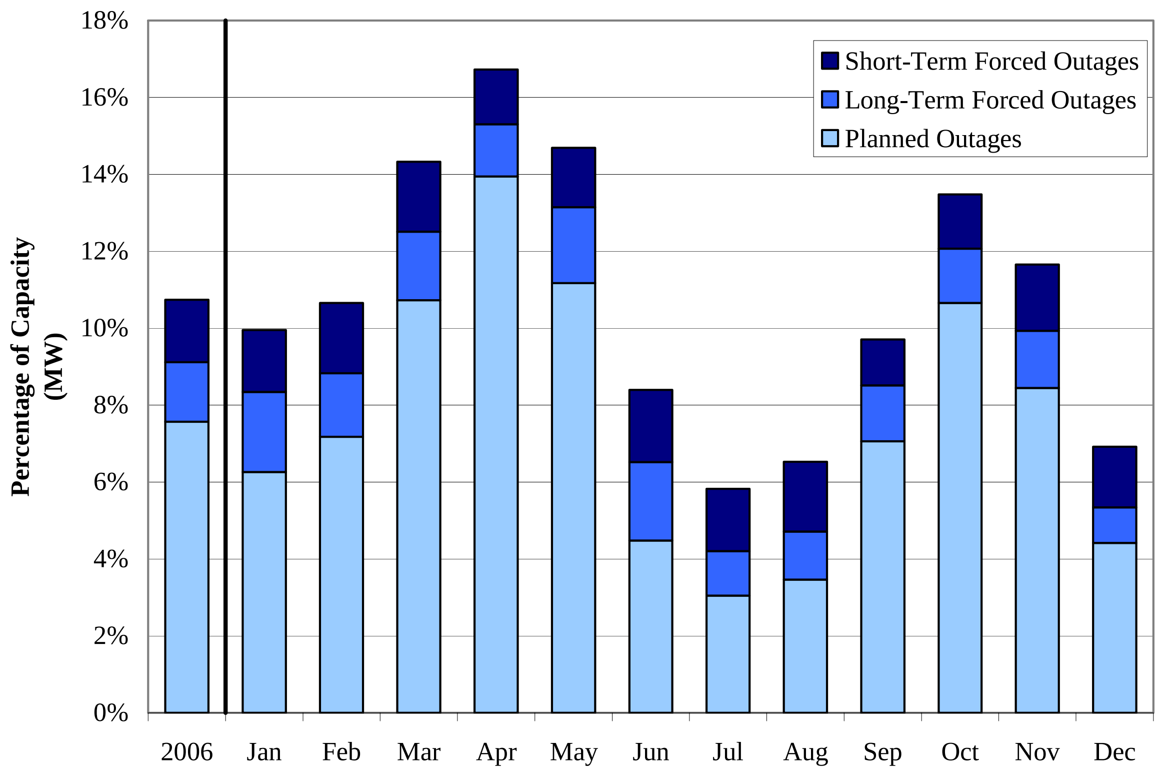
Peak Hour	6 PM	7 PM	7 PM	7 AM	2 PM	1 PM	2 PM	3 PM	3 PM	7 PM	6 PM	6 PM
Peak Date	Jan 5	Feb 20	Mar 21	Apr 4	May 30	Jun 22	Jul 31	Aug 1	Sep 7	Oct 3	Nov 30	Dec 7
Peak Load	82,909	82,852	79,862	72,063	98,466	96,518	116,382	114,340	78,885	77,141	78,218	85,333

Figure 12 shows that the peak load was generally higher than the emergency range of all online generation (i.e., higher than the maximum rating), which means that the Midwest ISO relies heavily on imports to satisfy its demands for energy and operating reserves in peak load hours. Figure 12 also shows that the peak hour in August was the second highest monthly peak, but it had the second most headroom (1.8 GW). This headroom was caused by lumpy load curtailments that occurred during the peak load event. With regard to the various categories of unavailable capacity, these figures show:

- Deratings in the day-ahead market were highest during July and August due to high temperatures and environmental restrictions forcing deratings of baseload capacity.
- Roughly 3 GW of nameplate capacity is permanently derated and unavailable for dispatch throughout the year.
- Forced outages account for a significant portion of unavailable resources during peak load events.

We next examine forced and planned generator outages on an average basis throughout the year. Figure 14 shows the different types of generator outages on a monthly basis.

Figure 14: Generator Outage Rates in 2006



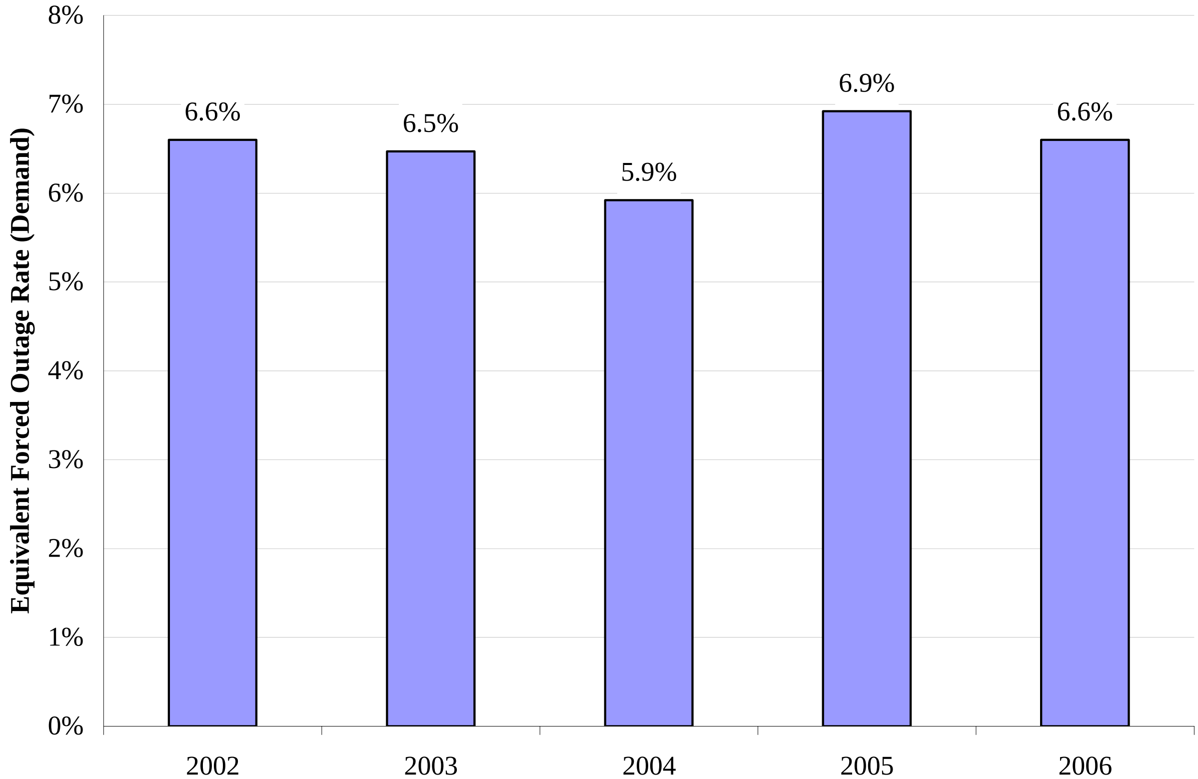
This figure shows the generator outages that occurred in each month during 2006 as a percentage of total market generation capacity. These values include only full outages – they do not include partial outages or deratings. The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).

The annual combined outage rate was almost 11 percent for the three categories of outages. As expected, this figure shows that the largest total outage levels occurred in the spring and fall when planned outages are generally scheduled to coincide with periods of low load. Planned outages exceeded 12 percent during the spring and 9 percent in fall. Total planned and forced outages peaked in April at almost 17 percent. Planned outages were relatively small in the peak load months of July and August.

The forced outage rate did not substantially increase during the summer – it remained at typical levels ranging from 3 to 4 percent. The analysis suggests that participants did not manipulate unit availability via claimed forced outages in 2006. The incentives to physically withhold in this manner are greatest during the tight load conditions characteristic of the summer months. The competitive assessment section of this report provides a detailed evaluation of potential physical withholding.

As a further summary of the outage rates in 2006, Figure 15 shows the Equivalent Forced Outage Rate-Demand ("EFORd") rates for 2002 through 2006. These data are un-weighted values provided by NERC. Because they are not capacity-weighted, outages of nuclear units and of very small units have the same effect on the region's EFORd rates. The EFORd metric includes both full outages and partial outages. The 2002 to 2006 period has seen consistent forced outage rates, from a maximum of 6.9 percent in 2005 to a minimum of 5.9 percent in 2004.

Figure 15: Equivalent Forced Outage Rate-Demand



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.

In addition to these main areas, we 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 that should enhance efficiency and the overall performance of the markets.

A. Day-Ahead Market Performance

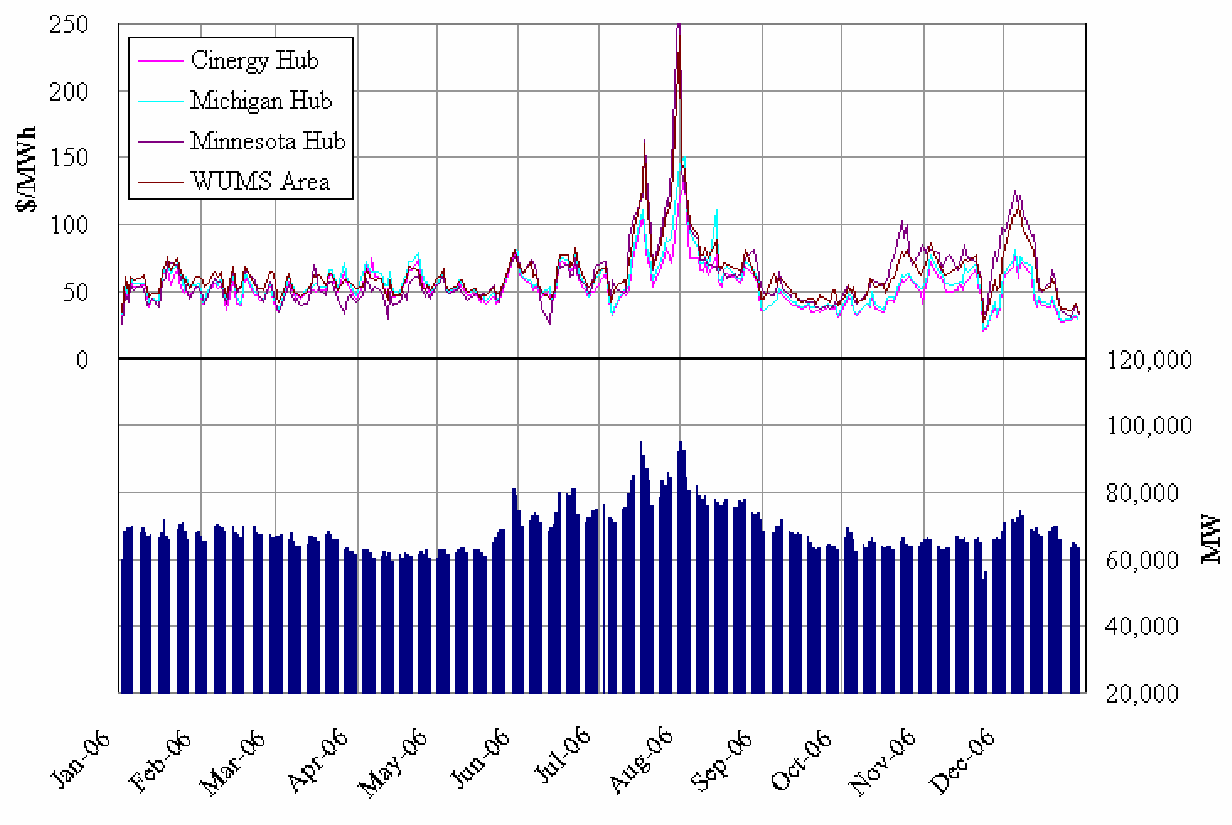
The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real-time. This valuable financial mechanism allows participants to hedge their portfolios and manage risk. For example, loads can insure against volatility in the real-time market by using FTRs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

The performance of the day-ahead market is very important because most of the power that is settled through the ISO markets is settled in the day-ahead market, FTRs are settled based on day-ahead market results, and most of the generator commitments are determined through the day-ahead market (although such commitments are not physically binding on the suppliers).

1. Day-Ahead Prices and Load

In this subsection, we evaluate day-ahead peak-hour prices in each sub-region relative to scheduled load (including net cleared virtual demand). This overview of day-ahead market results is shown in Figure 16.

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

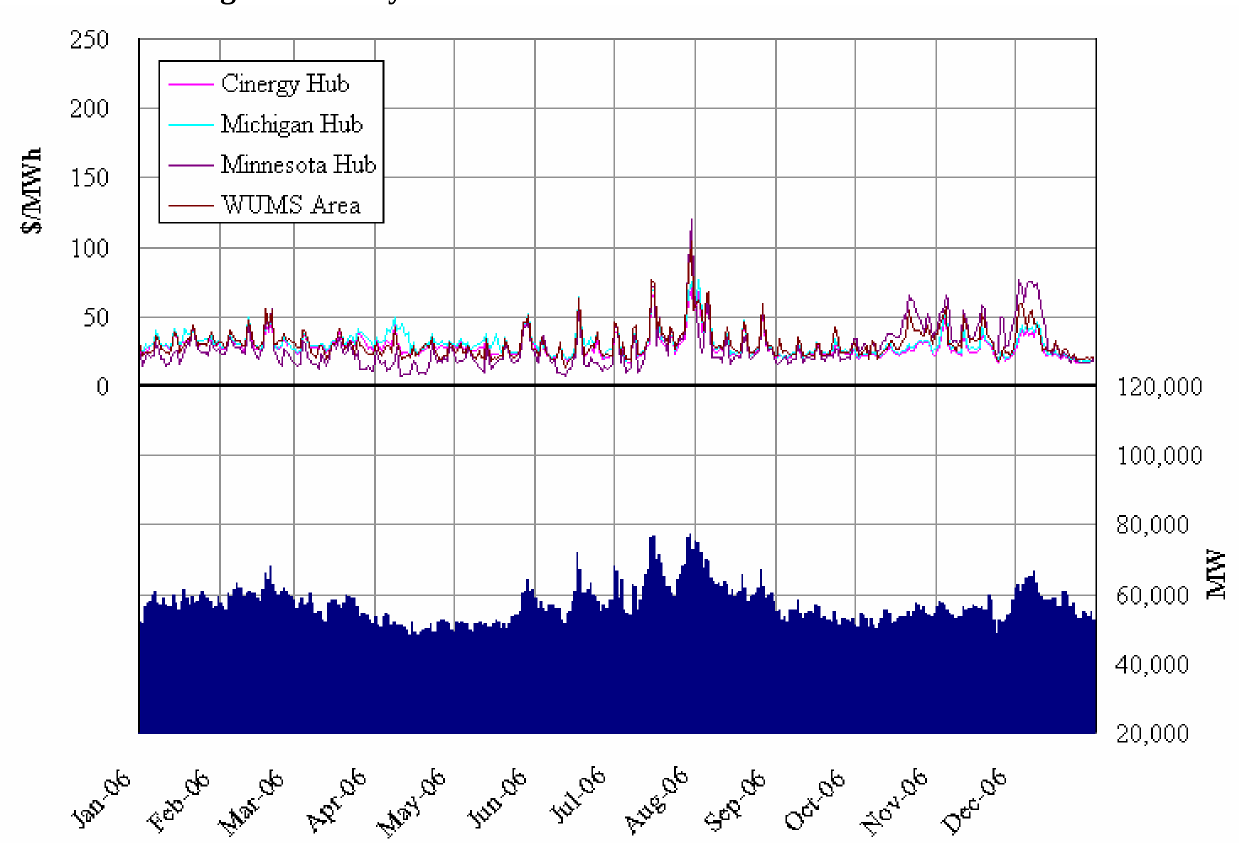


The figure shows day-ahead prices during peak hours (6am-10pm on weekdays) and the corresponding scheduled load (including net cleared virtual demand). In late July and early August, there was a spike in prices due to peak demand conditions associated with very hot weather throughout the Midwest ISO. This peak demand event is evaluated later in this section.

The most significant congestion occurred on the south to north constraints into Minnesota (these constraints also cause smaller price increases in WUMS). This congestion began in July and continued through the end of the year. On average, prices in Minnesota exceeded prices at the Cinergy hub during peak hours for the entire year by an average of $9.72/MWh. The main factor contributing to this pattern of congestion was reduced imports over the Manitoba Hydro interface. These imports patterns are discussed in the External Transactions section of this report. As noted previously, these patterns of congestion into Minnesota resulted in the definition of a new NCA for purposes of market power mitigation.

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 2006 and the Minnesota Hub prices substantially exceeded price levels in adjacent areas. Figure 17 shows the same analysis for off-peak hours.

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



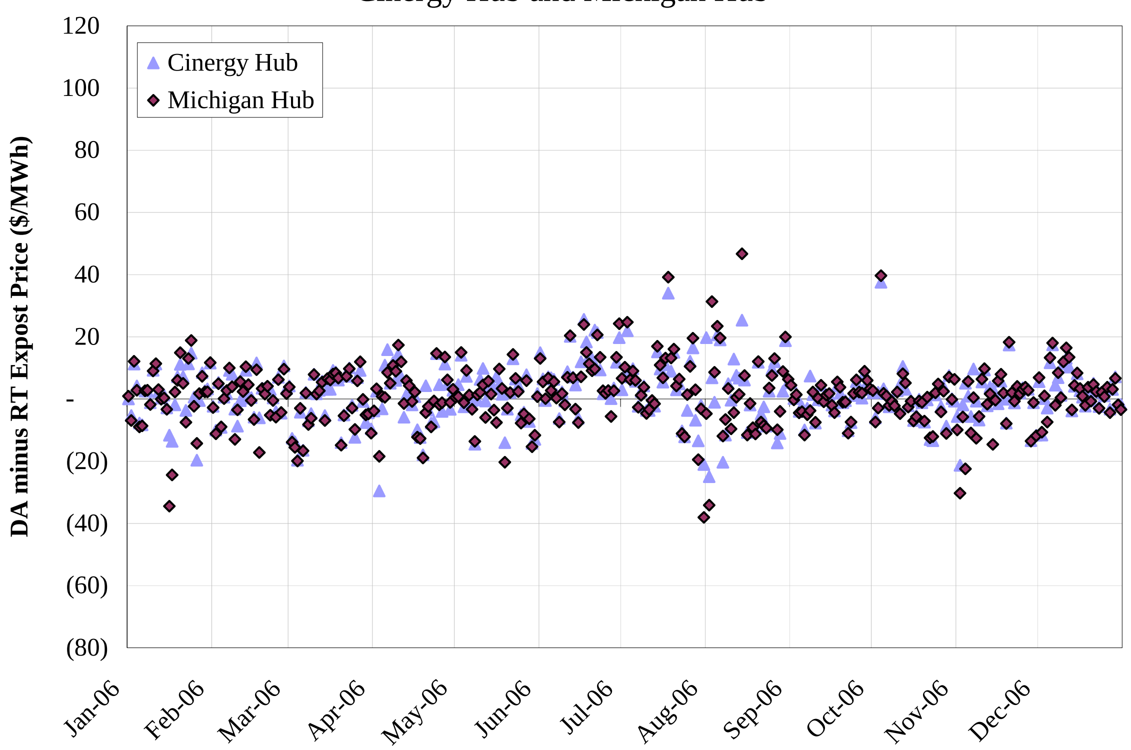
In 2006, off-peak prices were stable and showed much less congestion than peak hours. This result is in contrast to 2005 when off-peak hours showed frequent congestion events in the day-ahead and real-time market that resulted in negative prices in Minnesota. These negative prices subsided as some key generators provided more flexibility in 2006. In the first two weeks of December, there was a notable increase in Minnesota Hub and WUMS prices due to cold temperatures, outages, and reduced imports from Manitoba.

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. Because most wholesale energy traded through the Midwest ISO markets is settled at the day-ahead price, efficient outcomes in the day-ahead market help to provide appropriate market signals. In addition, the entitlements of the FTRs are associated with the results of the day-ahead market. When the day-ahead market closely reflects real-time operations, the payments to FTRs will fully reflect the prevailing system conditions.

In general, good convergence is achieved when participants make price-sensitive bids and offers in the day-ahead market that fully reflect expected real time conditions. To show the differences 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 four Midwest hubs.

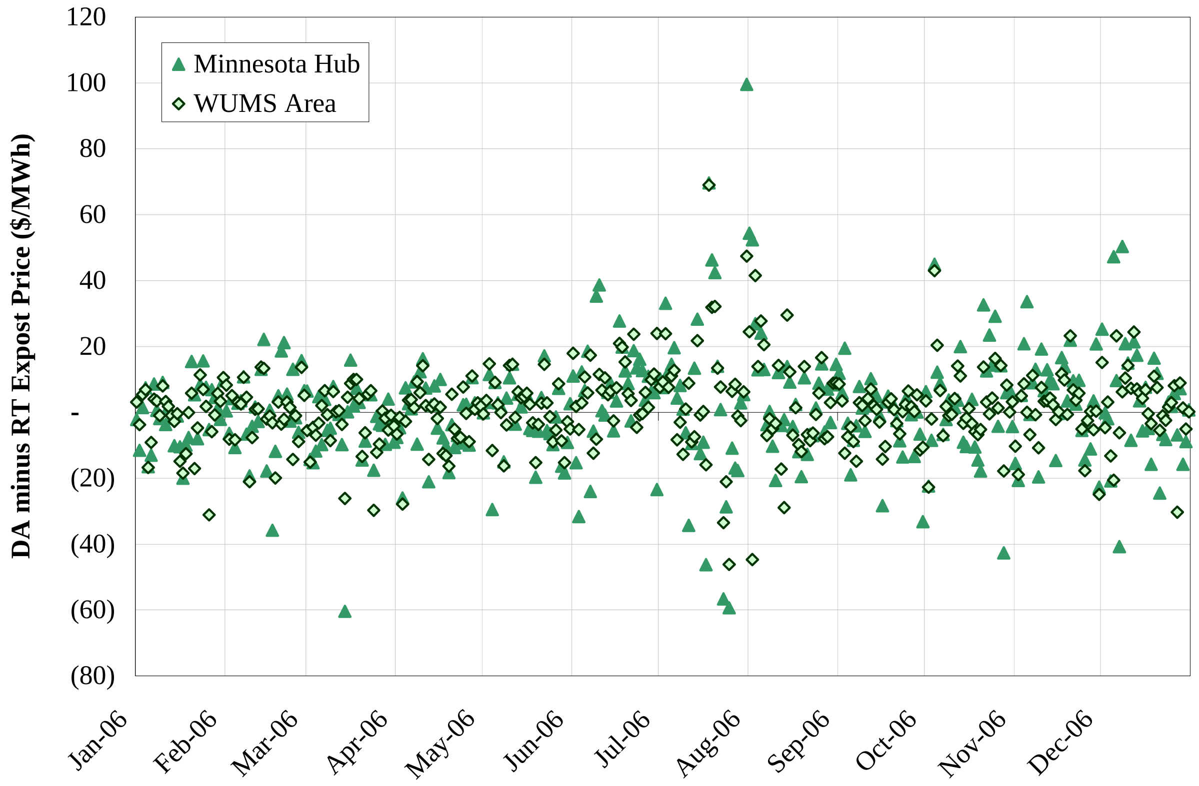
Figure 18: Average Daily Day-Ahead and Real-Time Price Differences
Cinergy Hub and Michigan Hub



The results for the Cinergy and Michigan hubs in the first figure show the average price differences over the year were small: $1.59/MWh for the Cinergy hub and $1.04/MWh for the Michigan hubs. These differences were largest during the summer when prices were the most volatile, as one would expect. In July and August, the Day Ahead premiums were $2.68 and $3.03 on average for the Cinergy and Michigan hubs, respectively. The larger premiums are also consistent with the higher potential RSG costs an entity that must buy energy in the real-time market faces. RSG cost allocation to real-time load purchases is discussed later in this section.

Figure 19 shows the same daily convergence results for the Minnesota hub and the WUMS area. These locations are different from the two locations shown in the prior figure because they are much more frequently affected by transmission congestion.

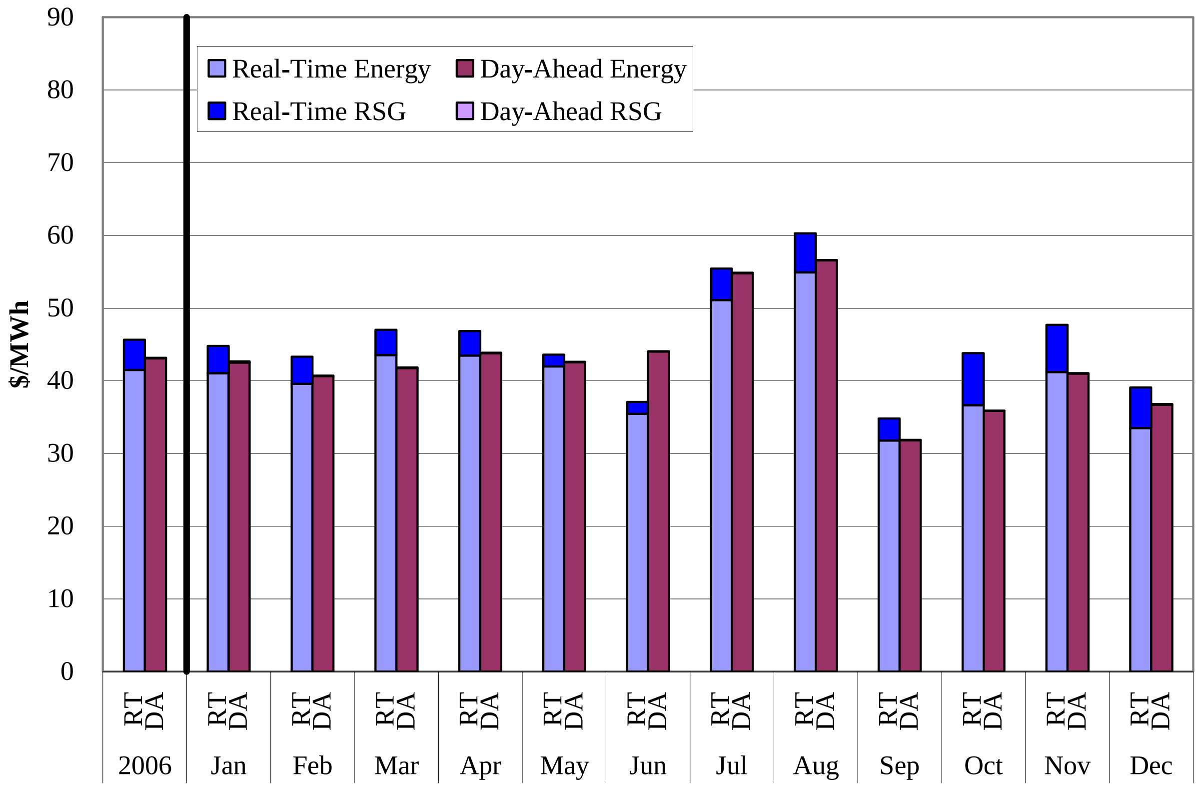
Figure 19: Average Daily Day-Ahead and Real-Time Price Differences
Minnesota Hub and WUMS Area



For the year, the average price differences in these areas were $1.53/MWh in Minnesota and $1.07/MWh in WUMS. The dispersion of the daily average differences, however, was wider in these locations than others due to the higher price volatility associated with more frequent transmission congestion. Like the price differences in other locations, the differences were the largest during the summer when prices were most volatile.

Although these differences can be relatively large on an hourly or daily basis, convergence is better evaluated over longer timeframes. Participants' day-ahead market bids and offers should reflect their expectations of market conditions the following day, but a variety of random factors can cause the real-time prices to be significantly higher or lower than expected. While a well-performing market will 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 convergence of prices on a monthly and annual basis at the Cinergy hub.

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



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 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.

Ignoring RSG costs, the average day-ahead prices at the Cinergy hub were slightly higher than real-time prices on average for 2006. Including RSG costs, however, the total real-time price was slightly higher than the total price in the day-ahead market. Cinergy real-time prices were generally close to day-ahead, with the exception of June. In June, the real-time prices plus RSG were lower on average by more than $5/MWh. Late in the year, the real-time price plus RSG allocation was substantially higher than the total day-ahead price. For the year, day-ahead prices at the Cinergy hub were $43/MWh, $2.15/MWh less than the real-time prices plus RSG costs (41/MWh plus $4.15/MWh). Figure 21 shows the same analysis for the Michigan hub.

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

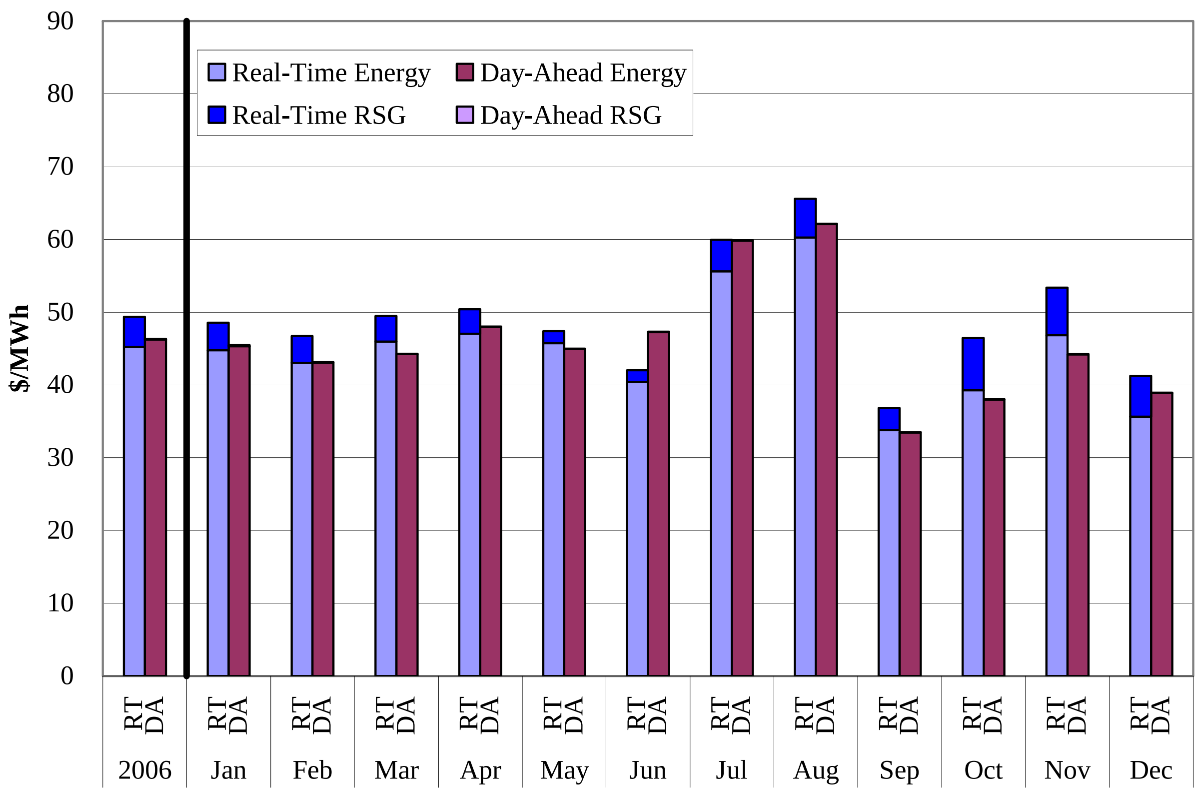
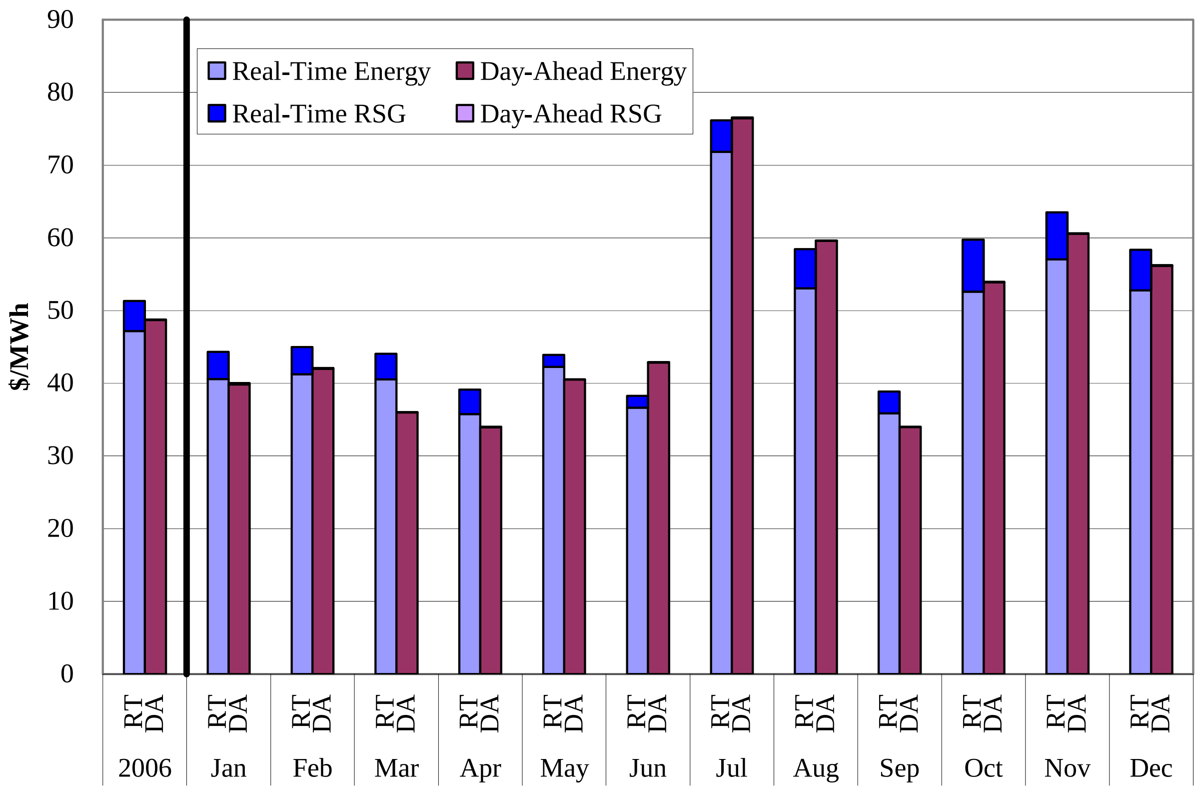


Figure 21, the real-time prices at Michigan hub followed a similar monthly pattern to those at the Cinergy Hub. For 2006, the day-ahead prices at the Michigan hub were $46 per MWh on average, while real-time peak prices at Michigan hub on average were $45 per MWh and real-time RSG costs were $4.15 per 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 locations that are more substantially affected by transmission congestion. Figure 22 shows the analysis for the Minnesota hub. Price convergence in Minnesota is likely to be more difficult to achieve because congestion in the West causes the Minnesota hub prices to be much more volatile than prices elsewhere in the Midwest ISO region.

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



As shown in the previous chart, prices for both the real-time and day-ahead trended upward at the Minnesota Hub in 2006 due to increased congestion into Minnesota. For the year, day-ahead prices averaged $49 per MWh as compared to real-time prices of $47 per MWh and $4.15 per

MWh RSG costs. Hence, price convergence at the Minnesota hub was comparable to convergence elsewhere, despite the congestion that affects this area.

The final figure in this series is Figure 23, which shows the same analysis for WUMS. The WUMS area is typically on the constrained side of the Minnesota-WUMS interface.

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

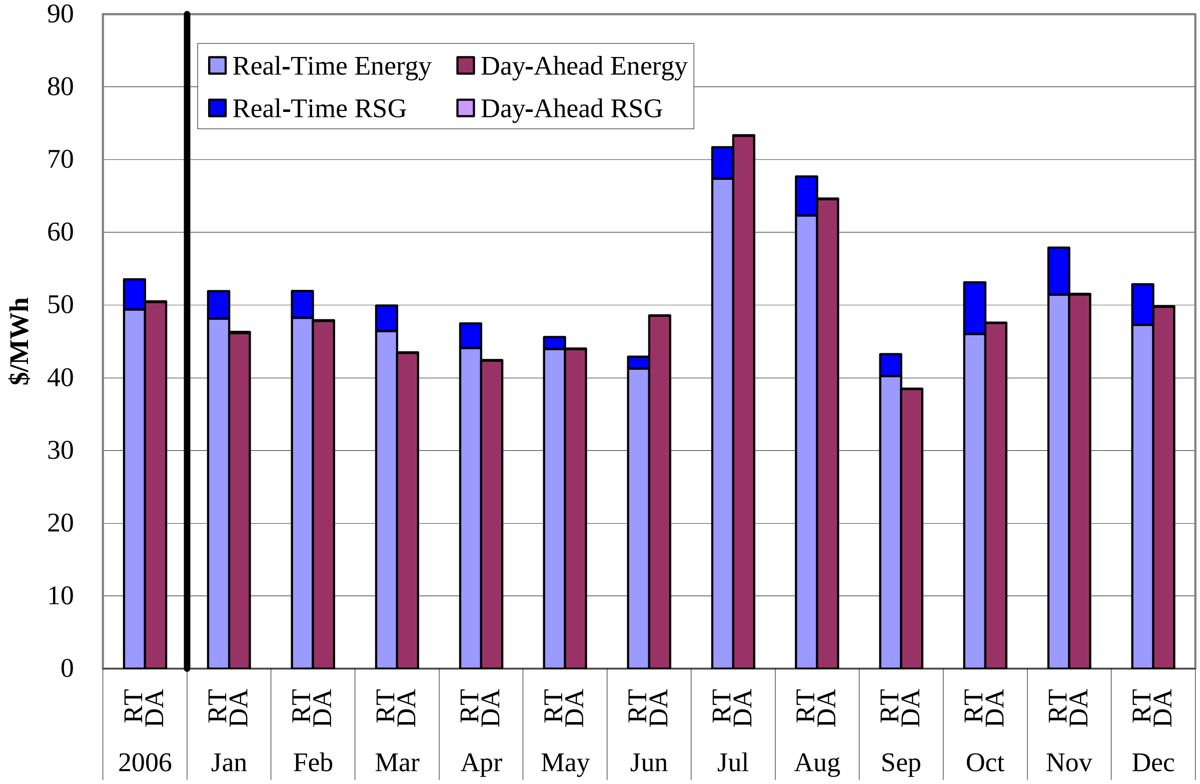


Figure 23 shows that average prices for the year in the day-ahead and real-time markets were very close in magnitude, with the day-ahead prices slightly exceeding the real-time prices prior to accounting for RSG costs. For the year, day-ahead prices averaged $50 per MWh in WUMS compared to real-time prices of $49 per MWh excluding RSG costs. Real-time prices exceeded day-ahead prices slightly in most months, but day-ahead prices were substantially higher than real-time prices in the summer months of June, July, and August.

Price convergence at both the Minnesota Hub and in WUMS over the entire year was comparable to the convergence at the Cinergy Hub and Michigan Hubs. This indicates that arbitrage has been relative effective, despite the increased volatility of the prices at these locations.

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

Table 3: Price Convergence – the Midwest ISO compared to Neighboring Markets

	Average Clearing Price			Average of Hourly
	Day-Ahead	Real-Time	Difference	Absolute Price Difference
Midwest RTO:				
Cinergy Hub	$43.14	$41.56	$1.59	$11.81
Michigan Hub	$46.30	$45.28	$1.04	$13.59
Minnesota Hub	$48.79	$47.27	$1.53	$19.73
WUMS Area	$50.52	$49.47	$1.07	$16.32
New England ISO:				
New England Hub	$63.49	$62.67	$0.83	$11.36
Maine	$59.32	$58.62	$0.70	$10.52
Connecticut	$70.95	$68.60	$2.34	$13.92
New York ISO:				
Zone A (West)	$51.85	$50.01	$1.84	$12.81
Zone G (Hudson Valley)	$68.02	$67.48	$0.54	$18.07
Zone J (New York City)	$75.88	$76.03	-$0.15	$20.06
PJM:				
AEP Gen Hub	$42.44	$43.68	-$1.24	$9.52
Chicago Hub	$43.89	$44.78	-$0.89	$9.52
New Jersey Hub	$57.02	$58.27	-$1.25	$15.23
Western Hub	$53.75	$55.27	-$1.52	$14.68

The table shows various statistics, including the average day-ahead and real-time prices from 2006, the difference in the annual average prices, and the average of the hourly absolute value of the price difference (which shows the typical difference regardless of the sign). For each market, we show these pricing statistics for several sub-regions (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. These premiums are consistent with the higher volatility, risk, and RSG costs associated with purchasing in the real-time market. The average price differences are generally larger in locations affected by congestion (New York City, New Jersey, WUMS and Minnesota).

The comparison of the average absolute value of the differences shows the absolute average price differences in areas that are not substantially affected by congestion are relatively small (less than $14/MWh). With the exception of PJM, the locations affected by congestion exhibited larger average differences, ranging from $16 to $20/MWh.

Overall, these analyses indicate that price convergence in the Midwest ISO has been consistent with the other markets that have been operating longer, despite the reduction in virtual trading volumes discussed in the following section.

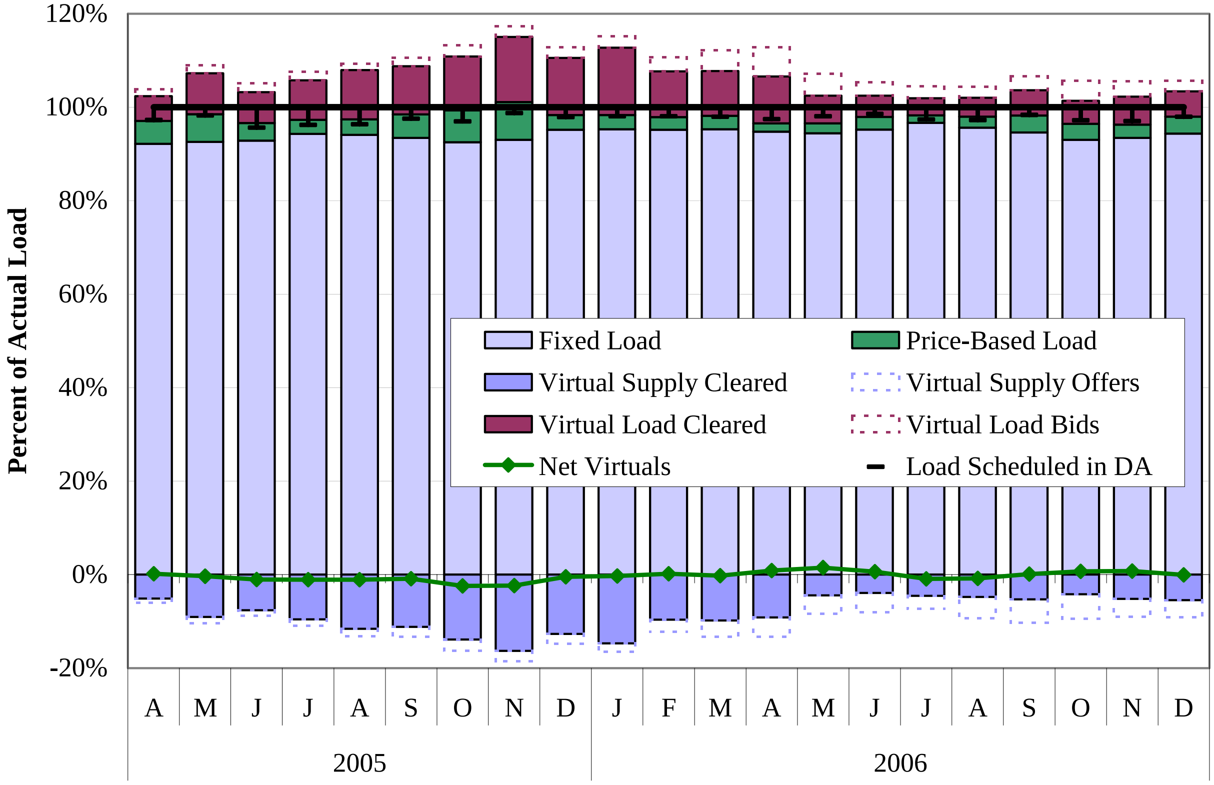
3. Day-Ahead Load Scheduling and Virtual trading

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 as discussed above.

Day-ahead load scheduling is the demand side of the day-ahead market. Day-ahead load schedules can be either price-sensitive or fixed. A price-sensitive load schedule is a load bid that cleared in the day-ahead market. This load is scheduled if the day-ahead price is equal to or less than the 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 shows the components of cleared schedules in the day-ahead market as a percentage of the actual real-time load on a monthly average basis. In addition to the physical load, this figure shows the virtual load and supply cleared in the day-ahead market.

Figure 24: Composition of Day-Ahead Load Scheduling as a Proportion of Actual Load

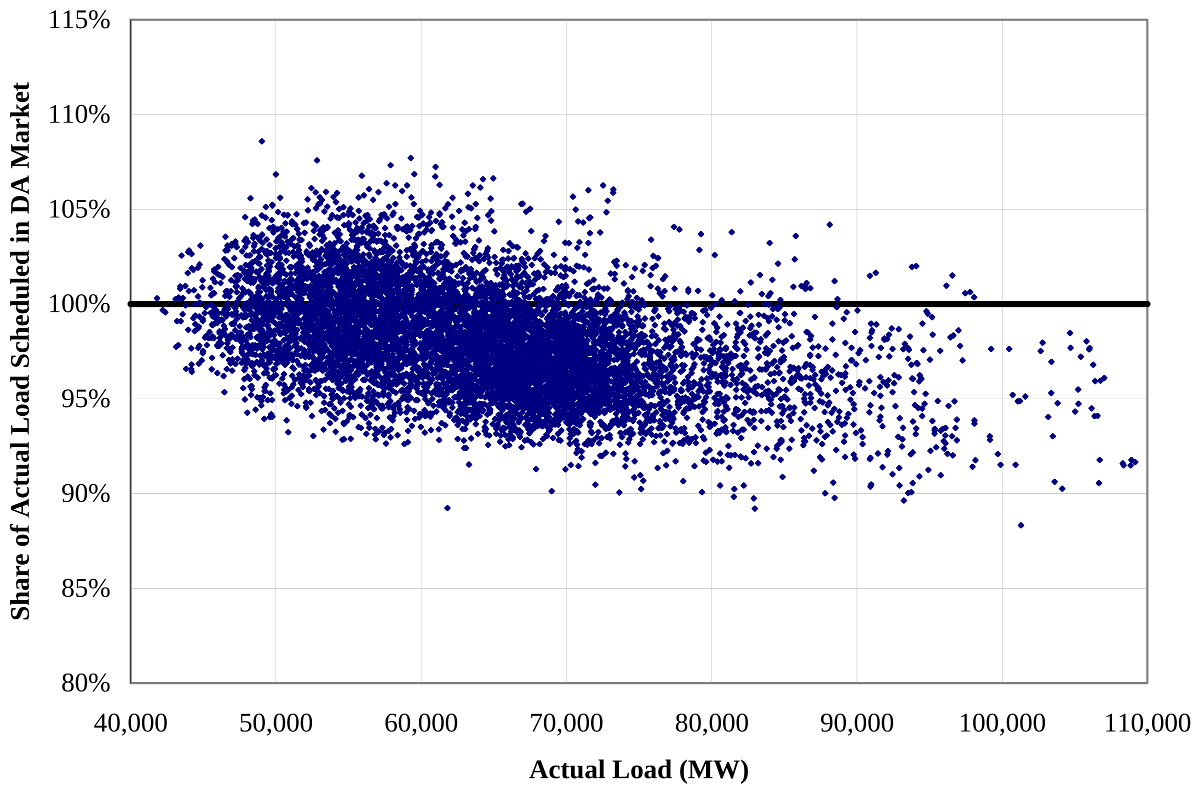


The largest component of load scheduled in the day-ahead market is fixed (i.e., will be purchased at any price). Price-sensitive physical load is very small in all regions other than WUMS. Virtual supply and demand cleared in the day-ahead market fell substantially after April 2006 when FERC issued an order requiring RSG costs to be allocated to virtual supply.

The net load (total load net of virtual supply) scheduled in the day-ahead market as a percent of the real-time load rose slightly in 2006. An average of 97.7 percent of the actual load was scheduled on net in 2006 in all hours, up from 97.1 percent in 2005. In the peak hour of each day (which is the hour that is most likely to require MISO to commit additional generation), 96.1 percent of the actual load was scheduled on net in the Day-Ahead market versus 94.7 percent in 2005. The higher scheduling levels have caused the Midwest ISO to reduce its reliance on peaking resources in the real-time, which contributed to lower RSG costs in 2006.

To examine the net scheduled load patterns on a market-wide basis, Figure 25 shows the percentage of real-time load scheduled in the day-ahead market relative to the actual real-time load. The figure indicates that the percentage of load scheduled generally decreased as the load increased in 2006. 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 due to their inherent operational inflexibility in the real-time market. 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 economic peaking resources to set prices more frequently in the real-time.

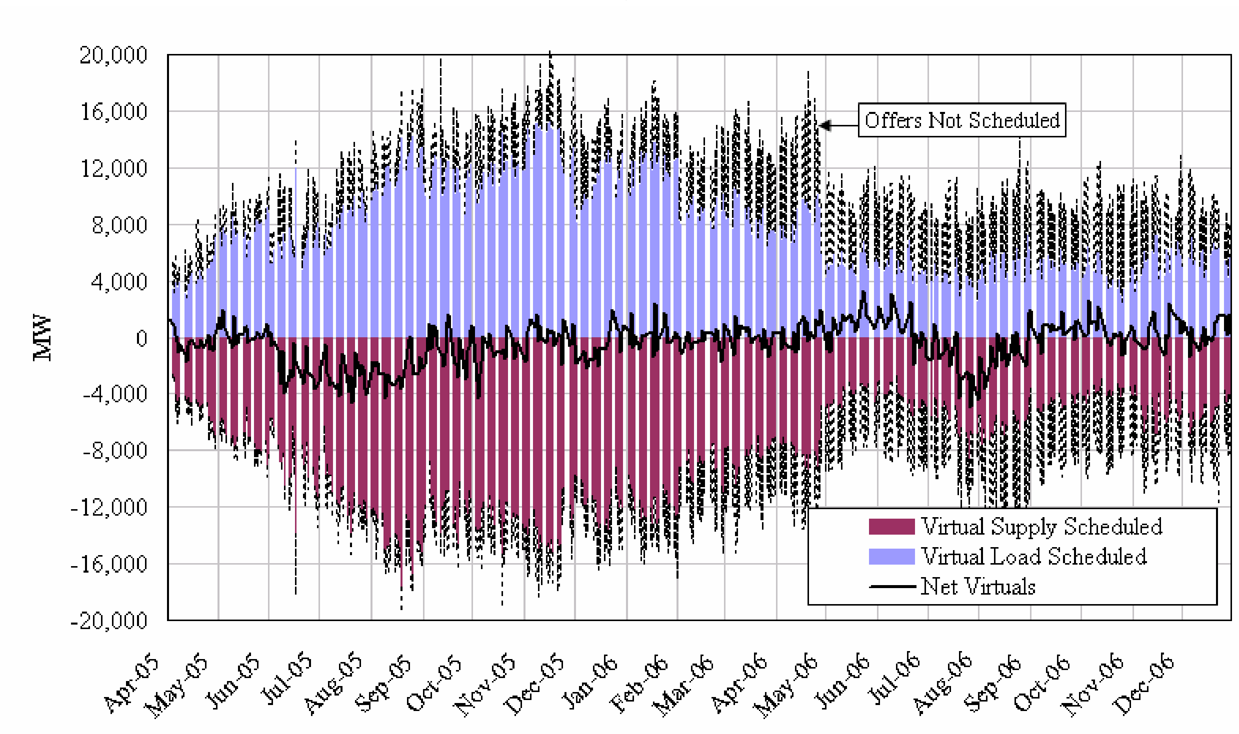
Figure 25: Net Load Scheduled Day-Ahead vs. Real-Time Load



Virtual trading is undertaken in the day-ahead market by participants that do not necessarily have physical load to serve or physical resources to offer. Virtual transactions established 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, its seller must then purchase $50 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 take virtual supply positions – that is to say, sell into 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 purchases in the day-ahead and sells at a higher price in the real-time. This trading will tend to cause day-ahead prices to converge with real-time prices, contributing to increased efficiency in the day-ahead market.

Figure 26 shows the hourly average virtual load bids and supply offers in the peak hours for each day from April 2005 through December 2006, as well as the quantities of each that were scheduled in the day-ahead market. The virtual bids and offers that did not clear (because they were not economic given the prevailing market prices) are shown as dashed areas atop the daily bars.

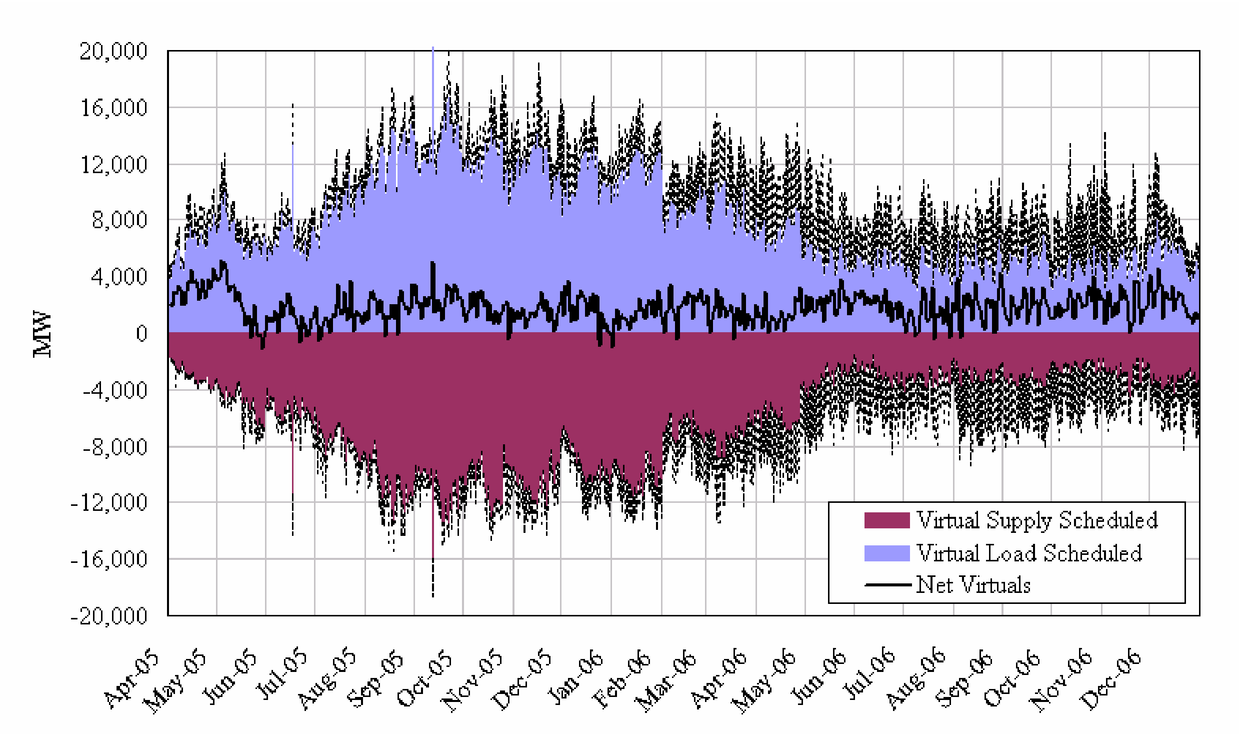
Figure 26: Virtual Load and Supply in the Day-Ahead Market
2005 – 2006: Peak Hours



Virtual trading volumes grew rapidly in 2005, more than tripling from the start of the market to December 2005. FERC issued an Order on April 25, 2006 requiring the allocation of RSG costs to virtual supply. Although the FERC order should only have affected virtual supply costs, both virtual supply and demand quantities have decreased. The total and cleared virtual bids and offers declined by roughly 50 percent beginning on April 27 and continuing through the end of the year. However, the reduced volumes of virtual trading have not weakened the convergence of prices in the day-ahead and real-time prices.

Figure 27 shows the same analysis as the prior figure, 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.

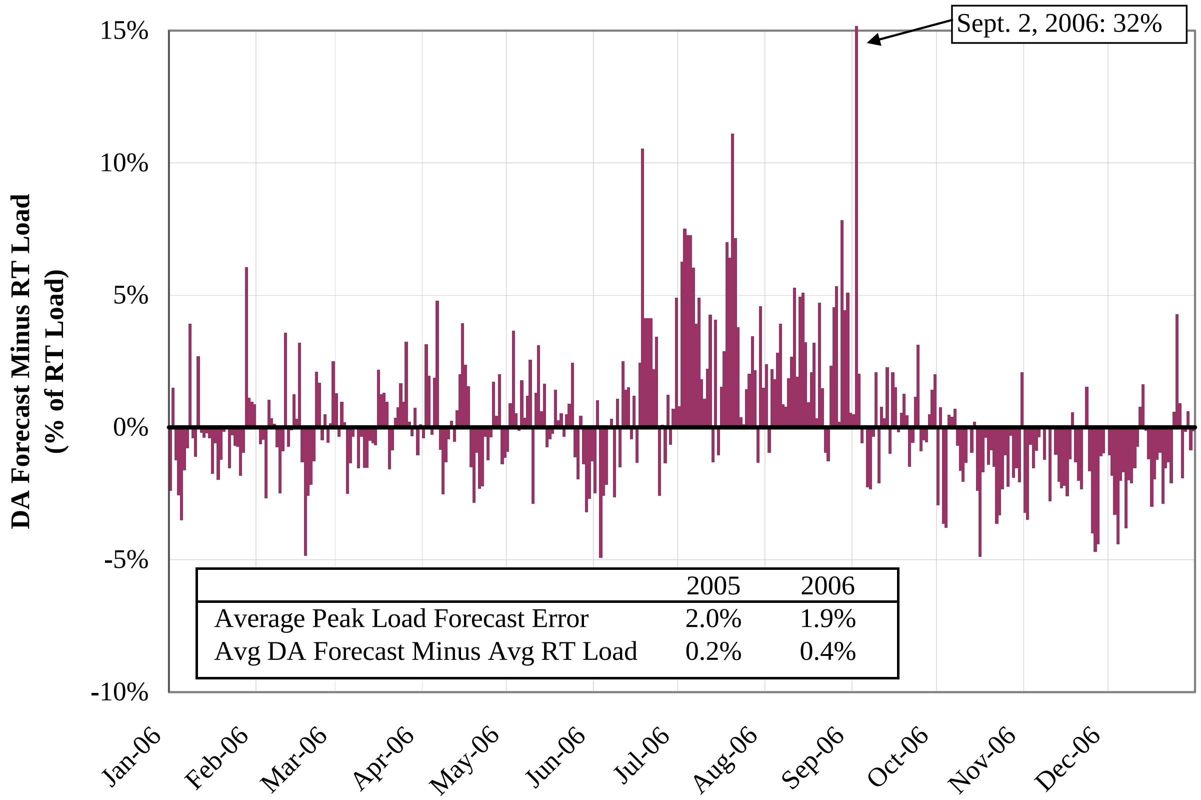
Figure 27: Virtual Load and Supply in the Day-Ahead Market
2005: Off-Peak Hours



Our next analysis examines the Midwest ISO 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 that or not commit sufficient resources to meet demand, both of which can be costly. Day-ahead forecasts may also be used by some participants in the day-ahead scheduling and bidding processes.

Figure 28 shows the percentage difference between the day-ahead forecasted load and real-time actual load for the peak hour of each day for 2006.

Figure 28: Daily Day-Ahead Forecast Error in Peak Hour
2006



The day-ahead forecast on average exceeded the average peak load by 0.4 percent in 2006. The average peak load forecast error was 1.9 percent on average (forecast error is the magnitude of the error, regardless of direction). These results indicate that the forecast was relatively good on average. The forecast error levels are lower than those in most other RTOs.

However, the figure reveals that load tended to be over-forecasted in the summer and under-forecasted in the fall, a pattern noted last year as well. In general, the higher errors occurred in the summer when uncertainty regarding weather-sensitive load was the highest. The Midwest ISO should investigate whether changes can be made to address the seasonal errors in its load forecasting. One step that the Midwest ISO has already taken to address this issue is that it has replaced its forecasting software in early 2007. We will monitor to determine whether this has improved the Midwest ISO's forecasting performance.

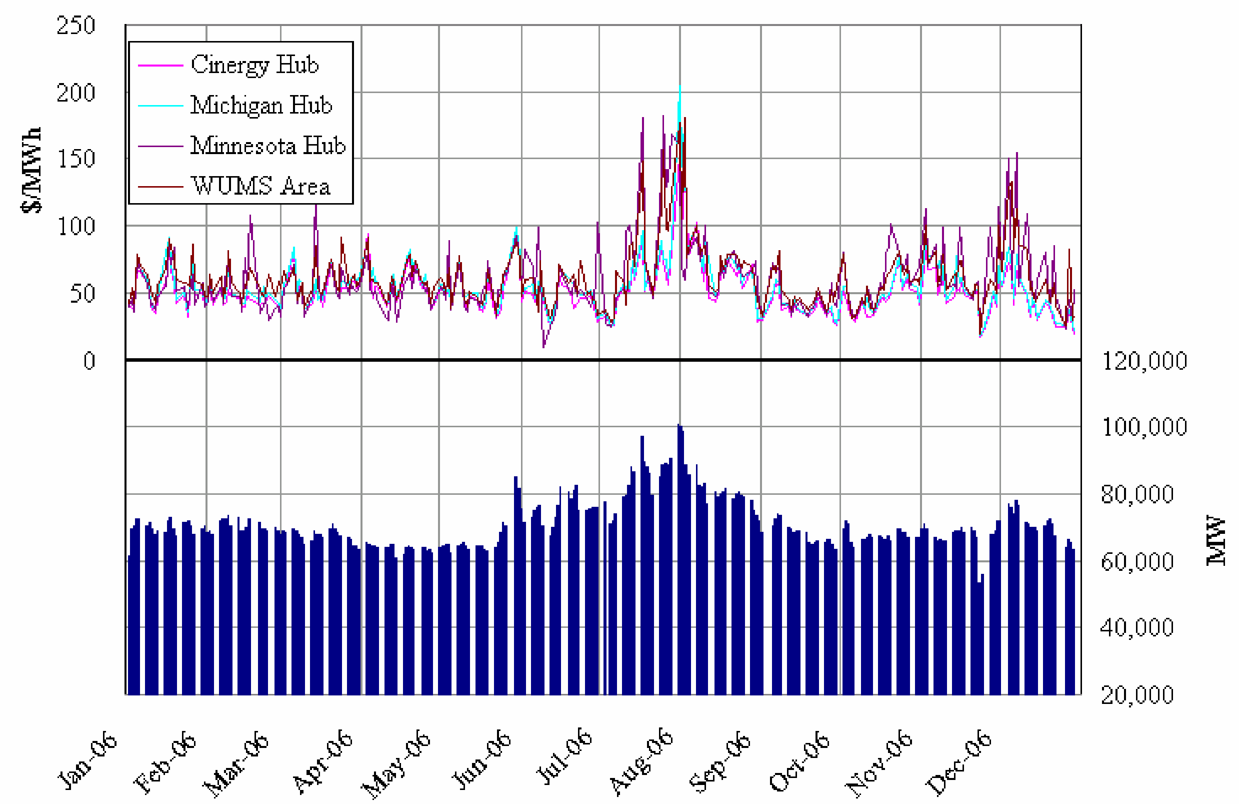
B. Real-Time Market Outcomes

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 close substitute for energy purchased in the real-time market, and therefore higher real-time prices will lead to higher day-ahead and forward market prices. Because forward purchases are 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 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, which is shown in Figure 29.

Figure 29: Real-Time Hub Prices and Load
Peak Hours

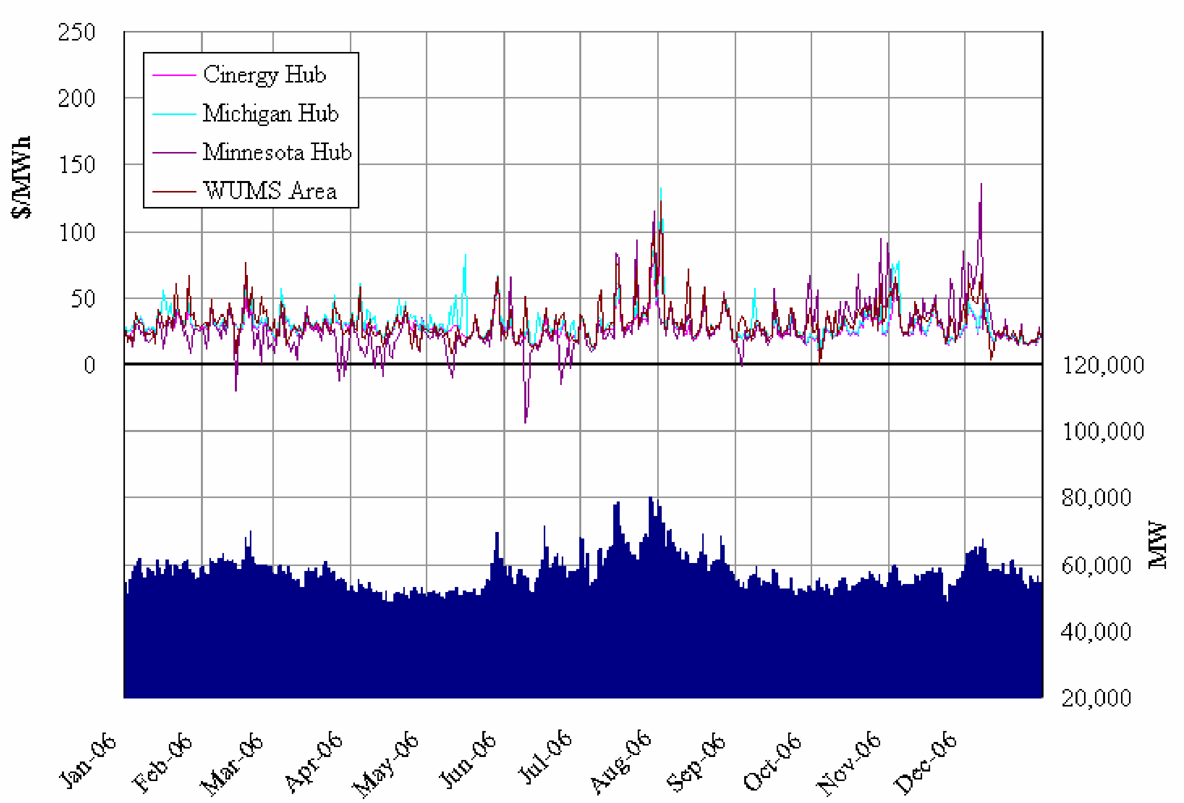


The figure shows a general correlation between peak load and peak price with some notable price separations due to congestion events. Compared to day-ahead, price differences in real-time are greater due, in part, to reduced bid flexibility and ramp limits that tend to exacerbate congestion in the real-time market.

Figure 29 also shows some notable price separation between the four locations due to transmission congestion. As in the day-ahead market, the most substantial congestion occurred into WUMS and Minnesota. In the first half of the year, prices in WUMS averaged $3.60 more than the Minnesota Hub (and $7 more than Cinergy) while in the second half of the year congestion into Minnesota become more severe and Minnesota prices averaged nearly $2.00 more than WUMS (and $16 more than Cinergy).

In late July to early August, peak demand conditions associated with extremely hot weather throughout the Midwest ISO area led to shortages of supply and associated high prices. In early December, there was a spike in Minnesota Hub and WUMS prices due to cold temperatures, outages, and reduced imports over the Manitoba interface. Figure 30 shows the same analysis for the off-peak hours.

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



The prices shown in this figure are substantially lower than in peak hours because relatively low-cost baseload coal resources set the energy price in most off-peak hours.

Early in the year, prices at the Minnesota hub were very low and sometimes negative due to congestion from Minnesota into WUMS. This congestion was due, in part, to reduced bid flexibility and ramp limits that can make congestion difficult to manage. Increases in flexibility and lower imports over the Manitoba Hydro interface reduced the frequency of this congestion in the second half of the year. The higher prices in early August and early December were less pronounced in the off-peak hours than in the peak hours.

2. Peak Load Event in 2006

Pricing during shortage conditions plays a very important role in providing the economic signals to govern investment in generation, transmission, and demand response resources. Hence, it is important to critically evaluate peak load events when the market is close to or in a shortage. Shortages occur when the resources in the market are insufficient to satisfy both the energy and operating reserves demands of the system.

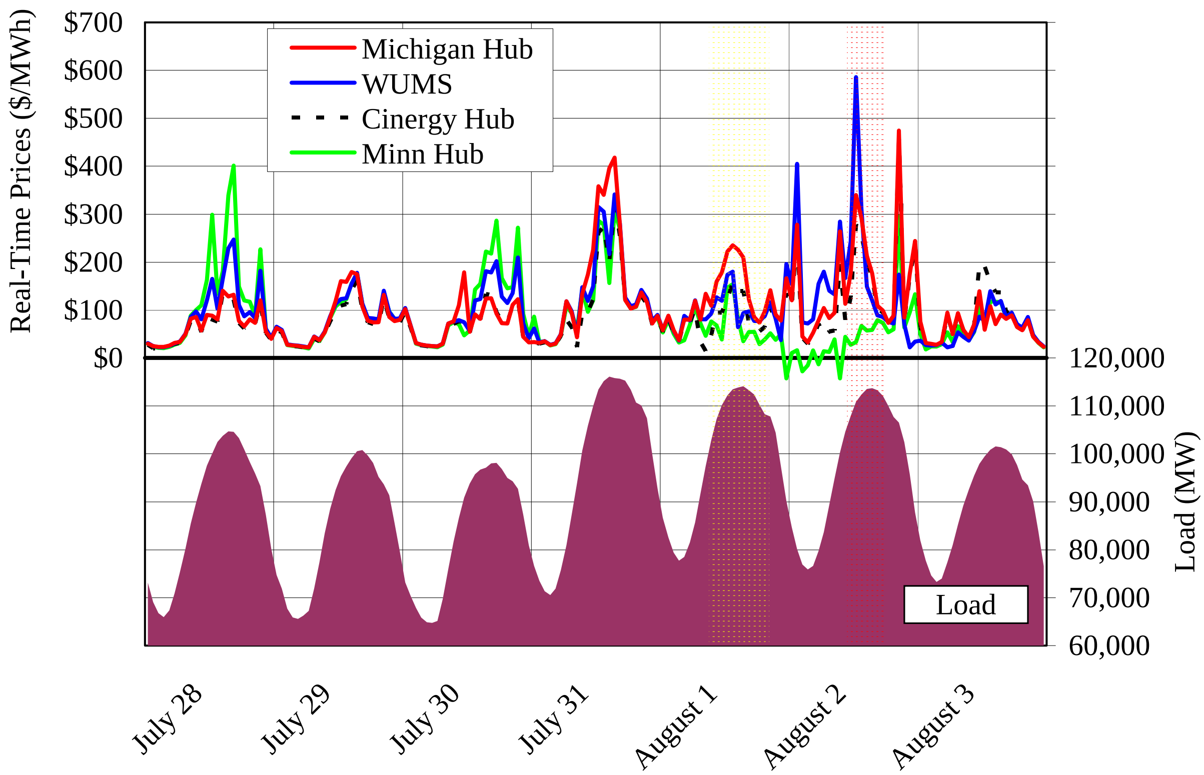
One peak load event occurred in 2006 in late July and early August. As shown in Table 4, at the end of July the Midwest ISO region experienced record high temperatures in several areas including 101 degrees in Minneapolis (18 degrees above normal high) on July 31.

Table 4: Summer Peak Load Event - Temperatures

	July 31		*August 1*		*August 2*	
	High Temp.	**Versus Normal**	**High Temp.**	**Versus Normal**	**High Temp.**	**Versus Normal**
Akron	88ºF	6ºF	91ºF	9ºF	90ºF	8ºF
Detroit	96ºF	13ºF	97ºF	14ºF	95ºF	12ºF
Indianapolis	93ºF	8ºF	93ºF	8ºF	93ºF	8ºF
Milwaukee	98ºF	17ºF	97ºF	16ºF	94ºF	13ºF
St. Louis	101ºF	11ºF	101ºF	11ºF	101ºF	11ºF
Minneapolis	101ºF	18ºF	79ºF	-3ºF	85ºF	2ºF

The extremely high temperatures throughout the Midwest ISO region resulted in record electricity demand. On July 31, the Midwest ISO set a new all-time peak at 116.4 GW. The previous peak demand was 112.2 GW in 2005. The peak hourly load was over 114 GW on the other two peak days. Emergency procedures were invoked by the Midwest ISO and by PJM during the peak hours on these days. In Figure 31, we show the loads, prices and emergency procedures invoked by the Midwest ISO.

Figure 31: Summer Peak Load Event – Pricing and Load

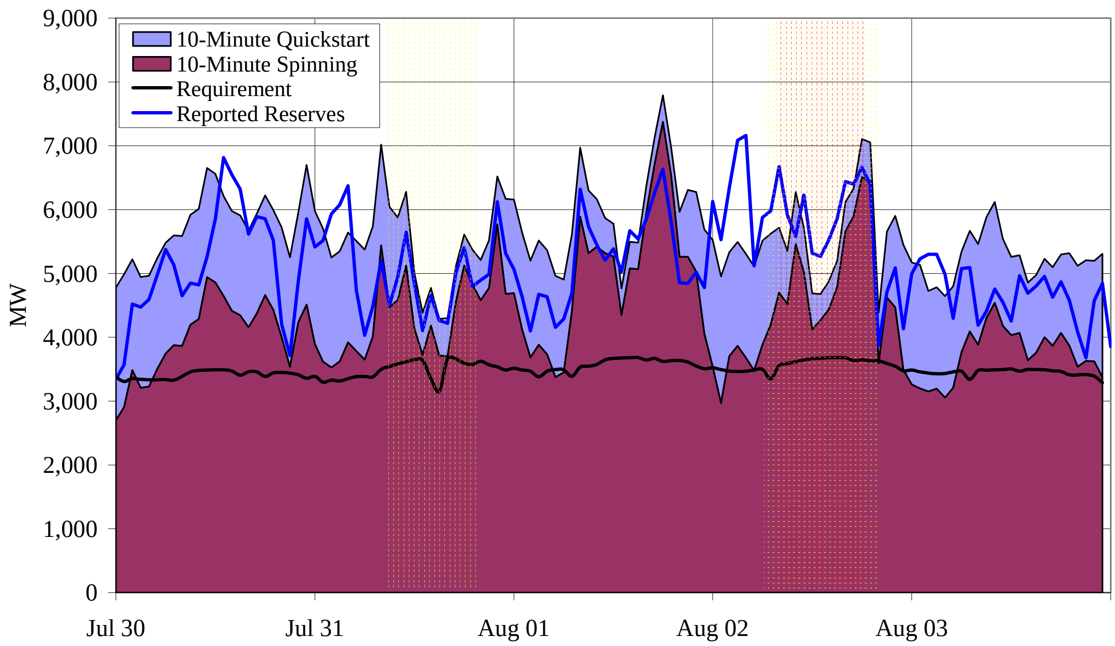


The figure shows that the hourly real-time prices were somewhat erratic during the highest demand hours during the peak demand days. Prices ranged from $200 to $350 per MWh during the peak hours on July 31. Prices during the peak hours on August 1 generally ranged from $50 to $150 per MWh and were less than $100 in the highest demand hour. Substantial congestion arose on August 2, which led to volatile prices and wide price dispersion across the Midwest ISO system. However, prices in the highest demand hours were generally less than $200 per MWh.

A level 2 Energy Emergency Alert (EEA 2) was called on August 1 that resulted in sizable changes to supply and demand. The EEA 2 resulted in voluntary load reductions of up to 3000 MW, export curtailments of 400-800 MW to PJM, and commitments of generators designated emergency-only of up to 900 MW. The load reductions and supply increases prevented operating reserve shortages that likely would have triggered shortage pricing. In effect, this demand-side management artificially moderated energy prices.

The next series of figures shows the contingency reserve levels in the Midwest ISO footprint and a number of its sub-areas. These figures are important because the clearest indicator of a true shortage is that the required level of operating reserves cannot be maintained. These figures show the contingency reserve requirement, the amount that we calculate was physically available (i.e., the amount of generation that can be available in 10 minutes), and the amount reported by the balancing authorities. The first figure shows the results for the entire Midwest ISO region.

Figure 32: Contingency Reserve Levels during Peak Event



The Midwest ISO did not actually incur a shortage. However, it would likely have been short of reserves on August 1 and 2 without the relief provided by the EEA 2 actions. When it invokes an EEA 2, the Midwest ISO calls for its LSEs to interrupt their interruptible load. The Midwest ISO estimates that it received approximately 3000 MW of load reductions in the peak hours on both August 1 and 2. The EEA 2 resulted in other sizable changes to supply and demand, including export curtailments of 400-800 MW to PJM and commitments of generators designed emergency only of up to 900 MW. These load reductions and supply increases prevented operating reserve shortages that would likely otherwise have occurred and triggered shortage pricing. Hence, the prices in the peak hours on August 1 and 2 were substantially lower than one would expect during a shortage.

The next figure shows the contingency reserves in the Michigan Electric Coordinating System ("MECS"), one of the transmission constrained sub-regions within the Midwest ISO. It also provides an indicator of when the sub-region is import-constrained. A reserve shortage in a constrained area is generally a concern when the transmission constraints into the sub-region are binding (because additional power cannot be imported if a contingency in the sub-region occurs).

Figure 33: Contingency Reserve Levels During Peak Event
MECS

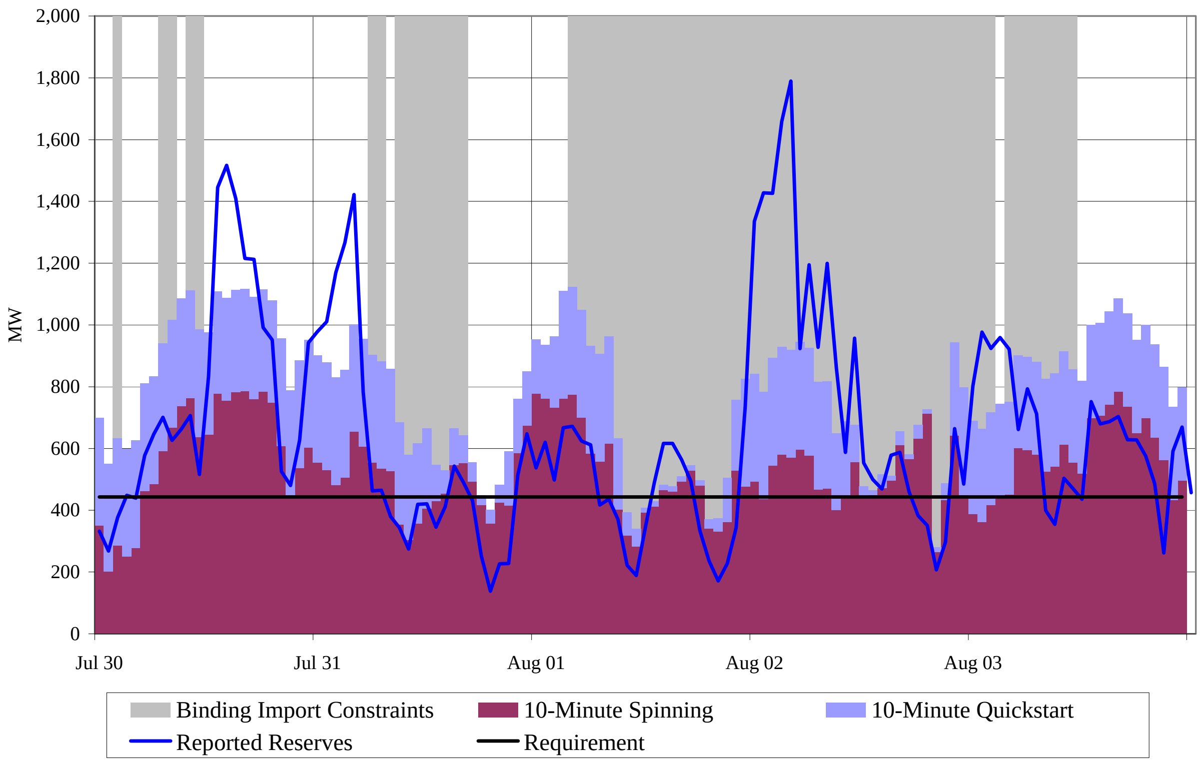


Figure 33 shows that MECS was short of reserves during brief periods during the peak hours. During these periods, the system was import constrained. These results indicate that it is important for MISO to track reserve levels at the sub-region level and to call the emergency pricing provisions for these areas when they cannot be maintained. If control areas unilaterally relinquish their reserves, it undermines efficient shortage pricing because the market will not perceive the shortage.

The prior two figures also show that the amount of reserves reported by the control areas can differ from the amount that actually exists. This occurs because not all of the undispatched resources in a control area are contracted by the balancing authority to provide reserves, and because reporting errors by the balancing authorities (the performance of some balancing authorities is considerably better than others).

Regarding other outcomes of the peak event, it generated more than $12 million in real-time RSG costs. The RSG costs occurred because the Midwest ISO relied heavily on peaking resources that did not cover their as-offered costs due to the inefficiently low prices that prevailed during much of the event. Absent the sizable changes in supply and demand resulting from the EEA 2 calls, the prices would have been higher in the peak hours and covered a much higher share of the peaking resources' as offered costs.

In summary, our review of the Summer Peak Load Event led to the findings that the Midwest ISO took appropriate actions to maintain reliability in invoking the emergency procedures. However, these procedures dampened the energy prices during the event. In addition, the reserve information provided by balancing authorities to the Midwest ISO was often incomplete or inaccurate. Further evaluation indicated that there were brief periods of shortage that occurred in certain local areas. We did not find evidence of significant economic or physical withholding during the peak event.

In response to the recommendations from our review of this event and the Midwest ISO's own evaluation of the event, the Midwest ISO has taken steps to:

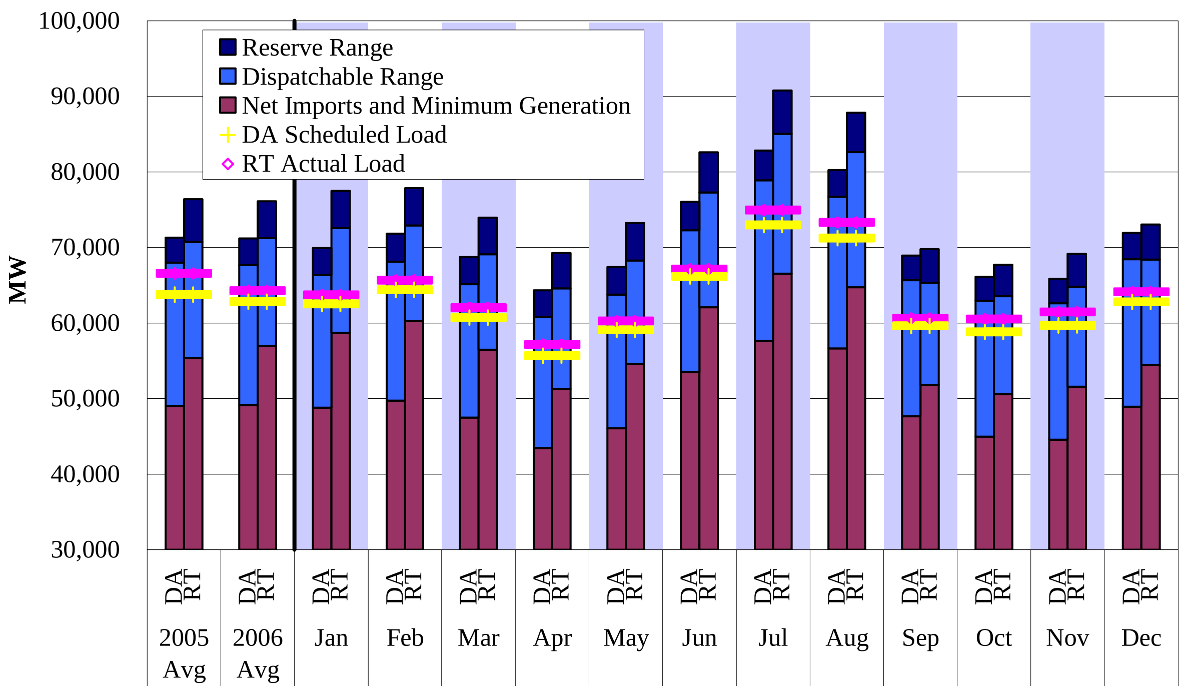
- Clarify its emergency operating procedures to reflect their relationship to the ARC procedures;
- Work with the IMM and stakeholders to develop pricing provisions that would prevent the EEA actions from depressing legitimately high prices during shortage conditions; and
- Improve its ability to call for voluntary demand curtailments when and where they are needed to maintain reliability.

3. 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 needs of the system. In general, the commitment of most generation that will be utilized in real time is coordinated by the day-ahead market.

The next figure shows the supply committed in the day-ahead market versus the supply that is ultimately available in the real-time market. It also shows the day-ahead scheduled load and the real-time load. The day-ahead capacity is higher than the net scheduled load because the units that are committed in the day-ahead market are not always scheduled at their maximum level.

Figure 34: Day-Ahead and Real-Time Generation
2006: All Hours



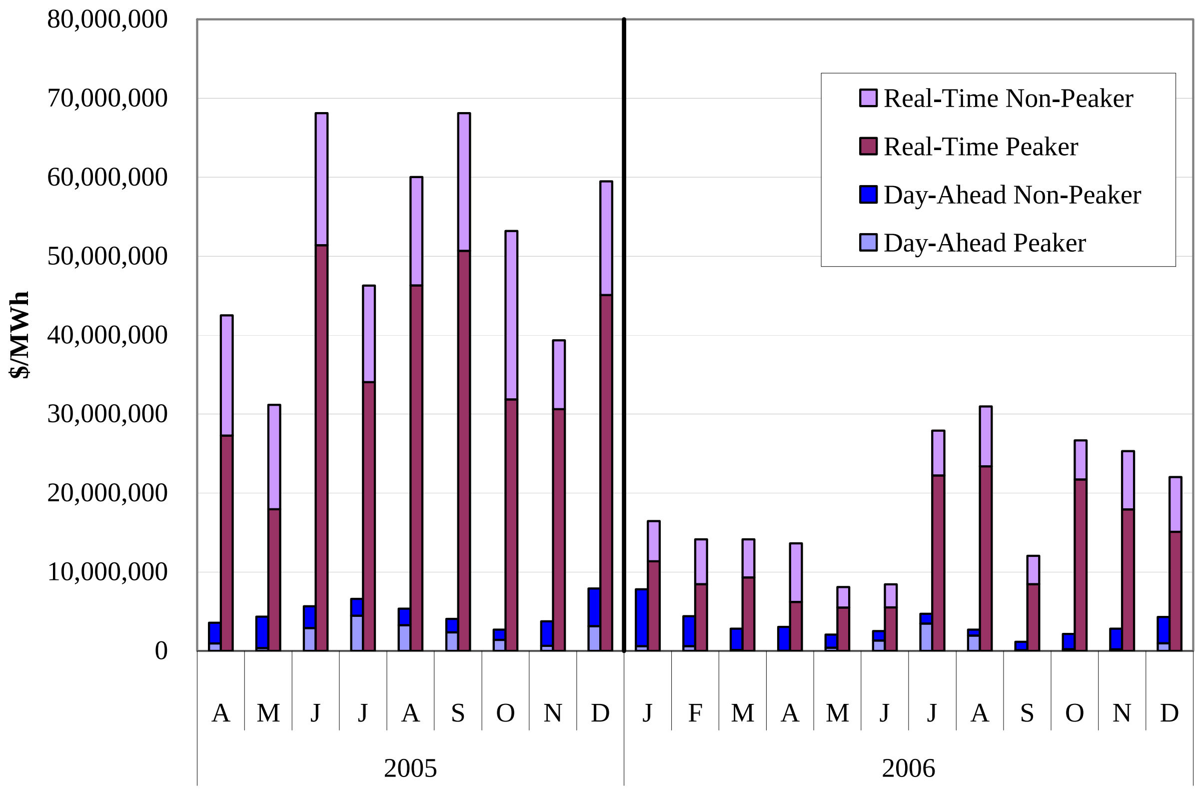
The figure shows that generation levels are generally higher in the real-time market. This can be attributed to several conditions including the self-scheduling of resources after the day-ahead market, under-scheduling of load in the day-ahead market, less net import in real-time than scheduled day-ahead, or net virtual supply in the day-ahead. However, over 97 percent of real-time generation is scheduled in the day-ahead market, which is an increase over 2005 due to higher load scheduling in the day-ahead market.

The figure also shows that dispatch flexibility is lost in the real-time market. Dispatchable range (EcoMax-EcoMin) as a percentage of total online capacity declines from 29 percent in the day-ahead market to 21 percent in the real-time. This reduction in dispatch range occurs when EcoMin is increased or EcoMax is decreased. These values are lower than the nameplate 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, an issue evaluated later in the report.

C. Revenue Sufficiency Guarantee Payments

Revenue Sufficiency Guarantee ("RSG") payments are made to certain units committed by the Midwest ISO when the LMP revenues in the applicable Midwest ISO market are not sufficient to cover their as-bid production costs. Figure 35 shows monthly RSG payments generated in the day-ahead and real-time markets to peaking units and other units.

Figure 35: Total RSG Distribution by Market
2005 - 2006



Resources that are not committed in the day-ahead market, but must be started to maintain reliability are likely recipients of RSG payments – this is “real-time” RSG because such units receive their revenue from the real-time market. Because the day-ahead market is a financial market, very little RSG is generated in it – a unit that is uneconomic will generally not be selected. Peaking resources are typically the most likely to warrant an RSG payment because their incremental energy is they are generally on the margin (i.e., the highest-cost resources) when they run and frequently do not set the energy price (i.e., the price is set by a lower-cost unit).

Figure 35 shows that the vast majority of RSG is generated in the real-time market and is payable to peaking resources. RSG payments to peaking units accounted for 71 percent of RSG payments in 2006. This is despite the fact that peaking resources produced less than 1 percent of the energy generated in MISO.

The figure also shows that RSG was much lower in 2006 than 2005. This is due to the following factors:

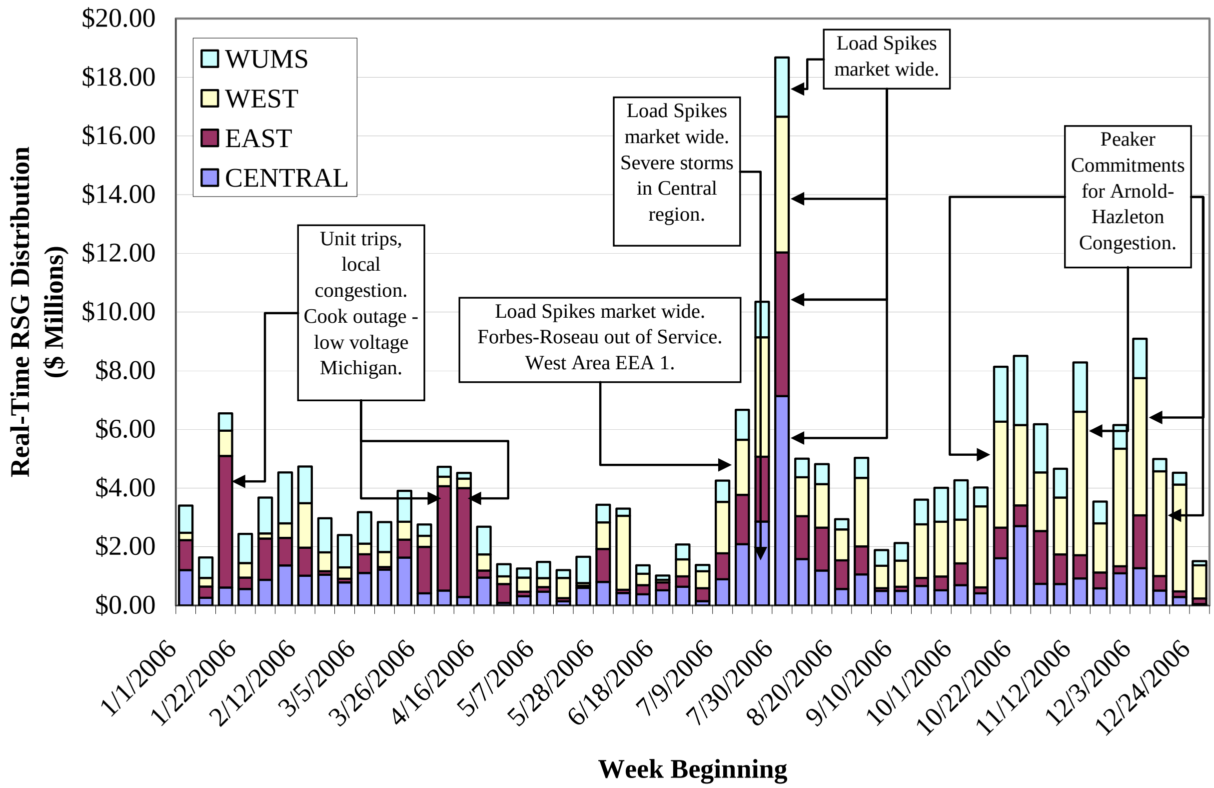
- Lower fuel prices will tend to lower generators’ production costs and the RSG payments that they are owed;
- Higher day-ahead schedules reduced the Midwest ISO’s reliance on peaking resources;
- Continued improvement by the Midwest ISO in the commitment and de-commitment of peaking resources reduced RSG costs.

Additionally, analyses later in this section show that peaking resources frequently do not set energy prices when they are running, causing them to appear to be running out-of-merit order (i.e., their offer price > LMP). This increases the likelihood that an RSG payment will be needed to cover as-offered costs.

In total, real-time RSG payments made in 2006 were $220 million as compared to more than $471 million in nine months of operation in 2005. As in 2005, the figure shows that RSG payments were generally highest in the highest load months of 2006 because the Midwest IS relies most heavily on peaking resources in these periods.

As an illustration of how some specific factors affected RSG costs, Figure 36 shows regional RSG payments data on a weekly basis. Showing the RSG payments on a weekly, sub-regional basis allows one to discern some of the key events that contributed to RSG costs

Figure 36: Weekly RSG Distribution by Region

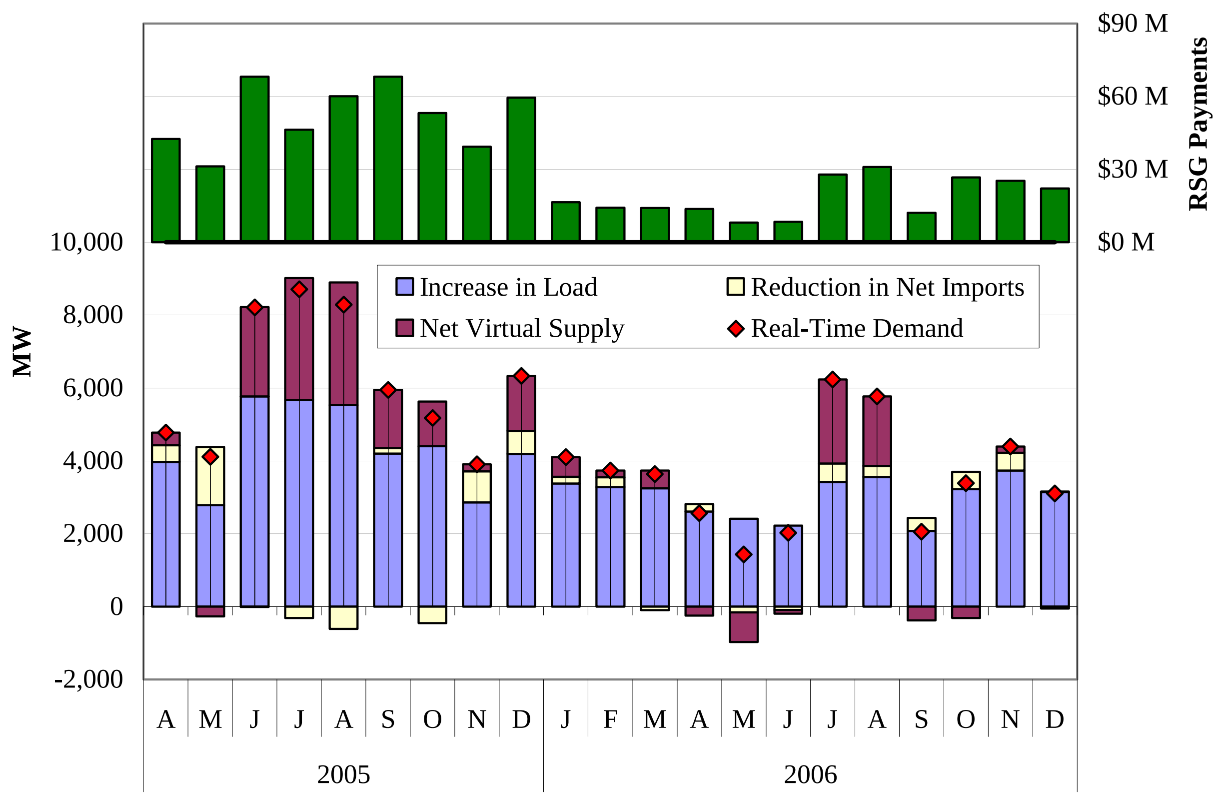


In general, commitments are made either to resolve transmission constraints or to satisfy market-wide capacity requirements. RSG costs can therefore often be linked either to specific constraints or to operating conditions. For example, the highest weekly RSG expenses were incurred during the last week of July and the first week of August when load exceeded 100 GW. Peak load conditions frequently require supplemental commitments to ensure a smooth ramp and adequate reserves throughout the system. As shown in the prior section, prices during the peak event in the summer did not fully reflect the shortage conditions, causing a number of high-cost generating units to require substantial RSG payments to cover their costs.

Transmission constraints also often require additional commitments that led to RSG payments. Late in the year, increased congestion into Minnesota and WUMS resulted in increased RSG costs because they frequently required supplemental commitment of peaking resources. Although not all of the RSG paid to generators in Minnesota and WUMS was due to congestion, the majority of the increase in such costs late in the year was a result of congestion.

The next analysis shown in Figure 37 shows a number of 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. The figure shows the average increase in generation and demand factors in the peak hour of each day of the month.

Figure 37: Drivers of Real-Time RSG



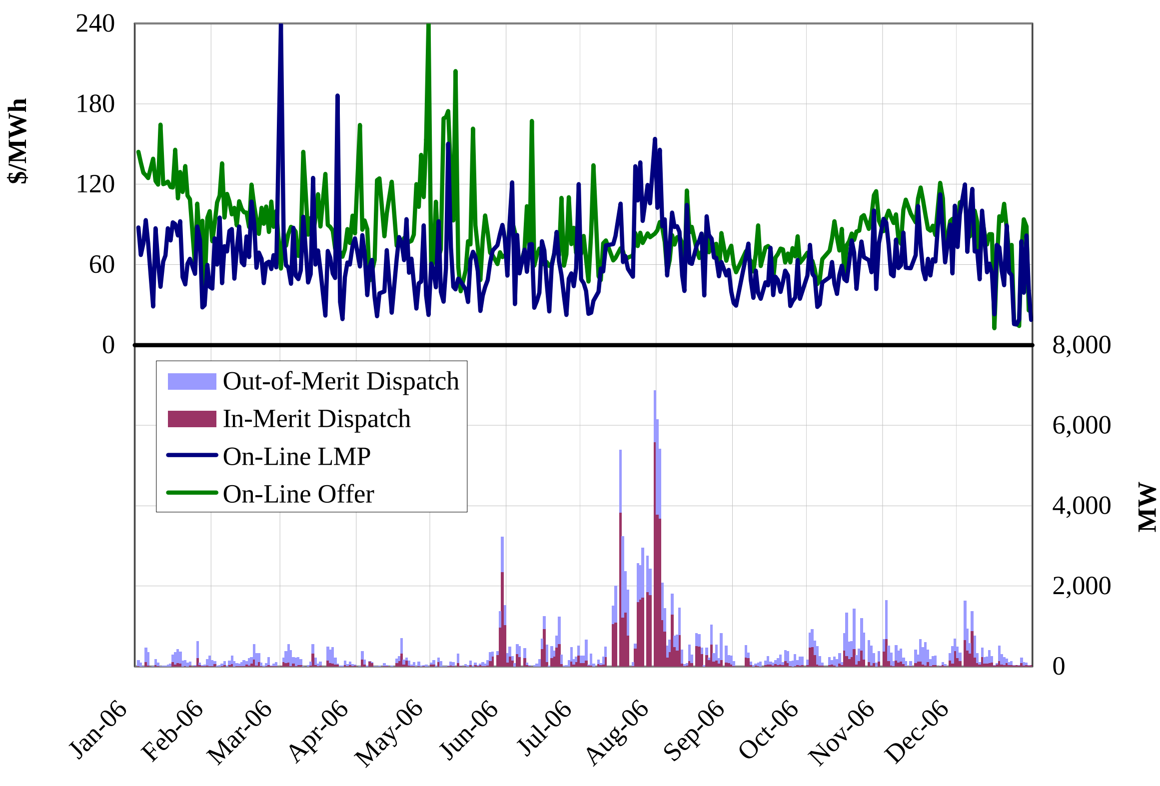
This analysis demonstrates that the change in net demand from the day-ahead to the real-time market is a primary driver of RSG. Hence, RSG decreased in 2006 as the demand for additional real-time generation decreased. The decrease in the demand for additional generation in the real-time in 2006 has been due to load being more fully scheduled (smaller increases in load from DA to RT), and less net virtual supply scheduling.

In both 2005 and 2006, the real-time demand and RSG was highest in the summer. This is likely because more peaking resources are expected to be needed in the summer. When these resources do not set prices, the incentive to schedule fully in the day-ahead market is reduced, which is one of the issues discussed more fully in the next sub-section.

D. Dispatch of Peaking Resources

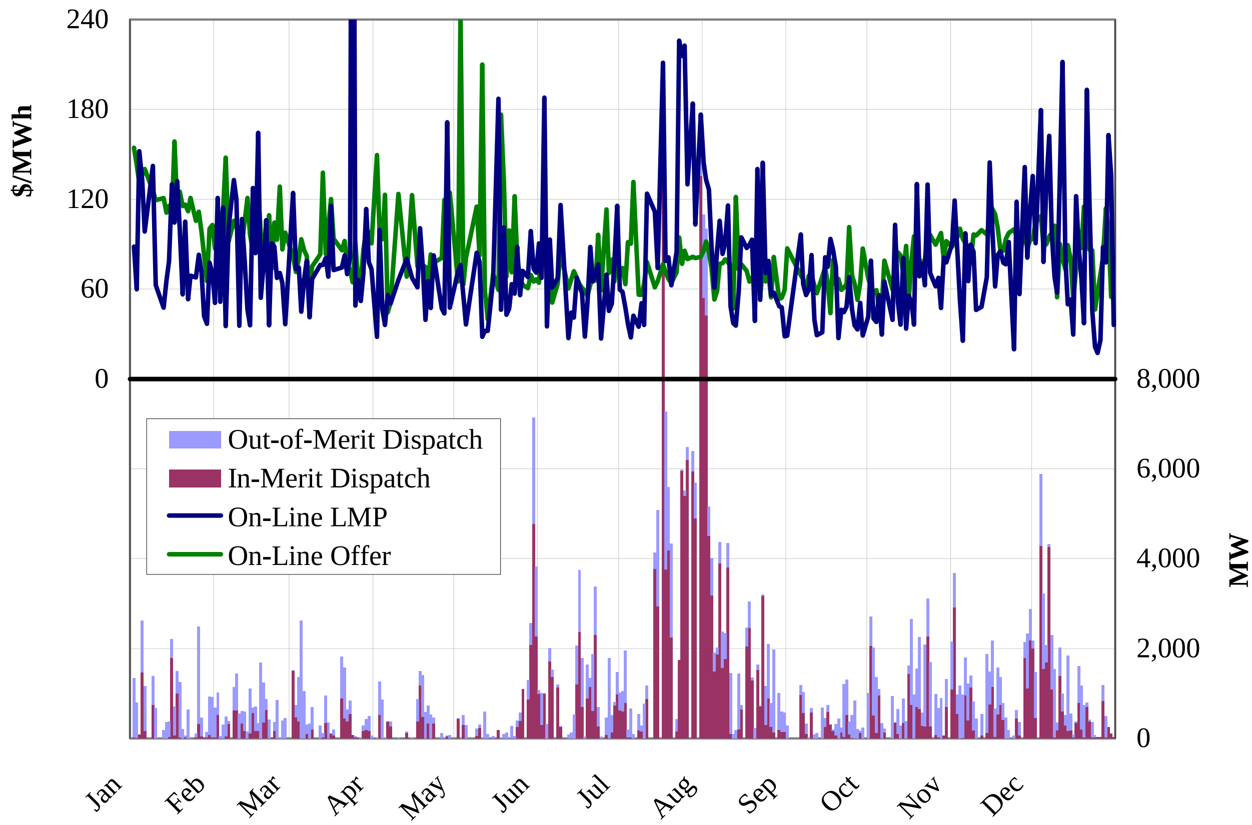
As discussed above, the dispatch of peaking resources is important because peaking resources are an important determinant of RSG costs and efficient energy pricing. The following two figures summarize the dispatch of peaking resources in 2006, showing the average hourly and peak-hour dispatch of peaking units by day. Figure 38 summarizes the dispatch of peaking resources in 2006, showing the average hourly dispatch of peaking units by day. The figure also shows the average offer prices from the peaking resources compared to the LMPs at the peaking resources' locations. The output of peaking resources is aggregated by merit status, whether the output is in-merit (LMP > peaker offer) or out-of-merit (LMP < peaker offer). Figure 39 summarizes the same information for peak hours only.

Figure 38: Average Daily Peaker Dispatch and Prices
All Hours



On average in 2006, 230 MW of peaking resources were dispatched on non-summer days and 978 MW were dispatched on summer days. This is much lower than dispatch levels in 2005 when the average dispatch of peaking resources ranged from 1,308 MW on summer days to 528 MW on non-summer days. The dispatch of peaking resources was highest on July 31st through August 2nd, with a daily average dispatch level as high as 6,600 MW and a peak dispatch level close to 13,000 MW.

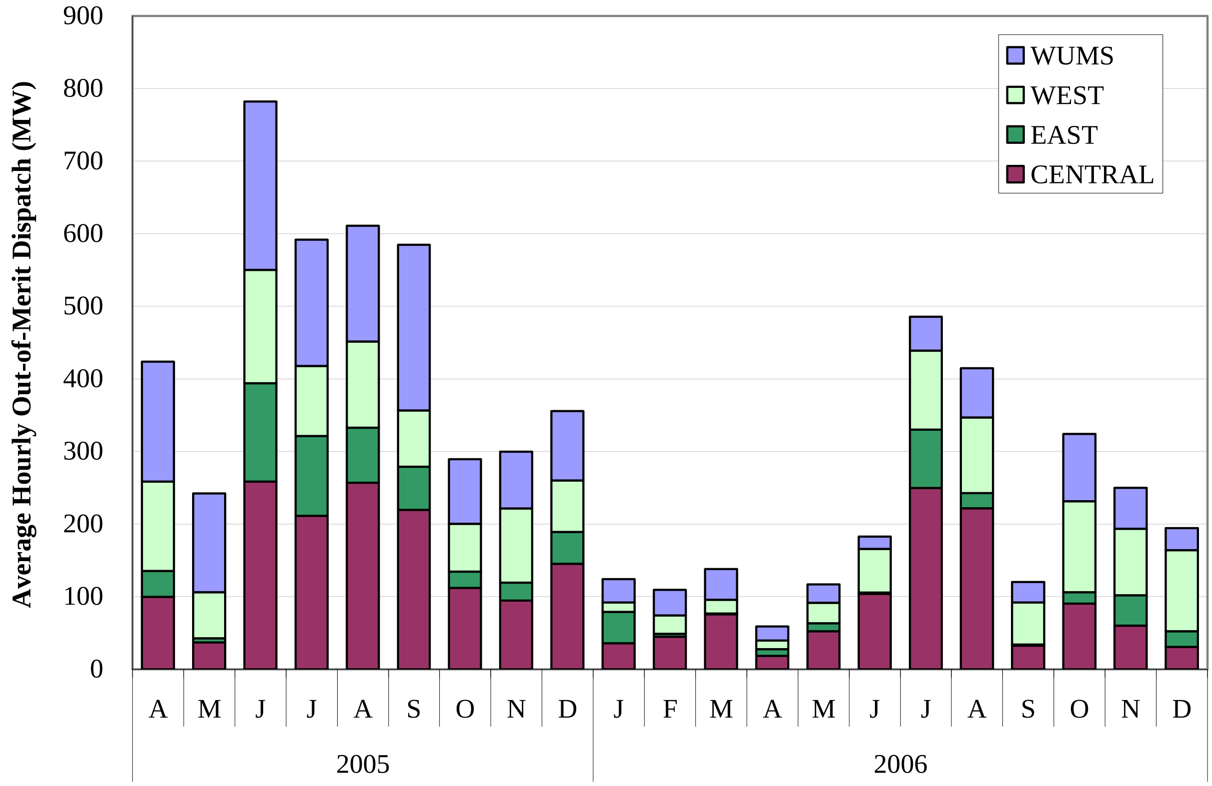
Figure 39: Daily Peaker Dispatch and Prices
Peak Load Hour



The figures also show the shares of the peaking resource output that are in-merit (LMP > peaker offer) and out of merit (LMP < peaker offer). Overall, 47 percent of the peaking resources are out-of-merit, indicating that they frequently do not set the energy price. Larger shares of peaking resources are in-merit in the summer, when they are heavily relied upon. These figures also show the average LMP at the online peaking resources' locations are compared to the average offer prices, showing that LMPs are often substantially lower. The implications of peaking resources running out-of-merit are discussed later in the report.

To provide a summary of the quantities of peaking resources that were dispatched out-of-merit, Figure 40 shows the hourly average of these quantities by region and month for 2005 to 2006.

Figure 40: Average Hourly Out-of-Merit Dispatch of Peaking Resources
2005 - 2006: All Hours



As discussed above, a peaking resource is out-of-merit when the hourly LMP is greater than its energy offer. Peaking resources committed for reliability are frequently out-of-merit and will receive real-time RSG payments for production costs not covered by LMP revenues. In both years, out-of-merit dispatch (and in-merit dispatch) was highest during the summer when load was highest. Compared to 2005, out-of-merit dispatch in 2006 was significantly reduced in every region except the West. Dispatch of peaking resources out-of-merit in the West increased due to the persistent congestion into Minnesota. South-to-north constraints in Iowa have been chronically congested since the fall of 2006. MISO operators frequently commit peaking resources to manage these constraints.

While not all of the peaking resources committed in the West are committed to manage congestion, the dispatch of peaking resources and associated RSG would have been lower absent the patterns of congestion that emerged in the second half of the year.

In evaluating the out-of-merit dispatch of peaking resources, it is important to recognize that starting more peaking resources than the minimum needed (or if they are started earlier than needed) will increase the likelihood that the peaking resources will not set prices and will, therefore, be dispatched out-of-merit order. When excess peak resources are online, they will tend to run at their minimum generation level, which makes them ineligible to set prices and results in higher out-of-merit quantities.

The reduction in out-of-merit dispatch of peaking resources in 2006 reflects, in part, the decreased reliance on peaking resources overall the resulted from higher levels of load scheduling in the day-ahead market. However, operational improvements by the Midwest ISO also contributed to the reduction in out-of-merit dispatch levels. The Midwest ISO made a number of operating improvements after the start of the market and during the first year of operations that has improved the commitment of peaking resources and reduced the frequency of excess online peaking resources. The improvements included:

- Improved tools used in the Reliability Assessment Commitments (“RAC”), including additional information on unit economics relative to system constraints.
- Improved operator interfaces and tools used in the real time that allow operators to better track online and available capacity, as well as actual versus expected unit status. This improves their ability to determine when units need to be committed in real time and when peaking resources can be decommitted.

The commitment and dispatch of peaking resources can be improved further by implementing a “look-ahead” capability for the current real-time market that would determine when gas turbines should be committed as an economic dispatch decision (rather than as a reliability or capacity decision). Gas turbines, which are most of the peaking resources in the Midwest ISO, are unique in that they can provide capacity (operating reserves) without being turned on. Hence, the decision to turn them on should generally be an economic one. Currently, operators commit and de-commit turbines based on operating criteria. Allowing a market model to determine when gas turbines should be committed and de-committed should reduce the out-of-merit dispatch quantities, reduce RSG payments, and improve the ability of peaking resources to set energy prices.

As discussed further in relation to ancillary service markets, additional reductions in commitments and related RSG costs can be achieved with the introduction of operating reserve markets. Such markets allow the value of unit operating characteristics, such as quick start capability, to be more fully captured by the markets. For example, large portions of the gas turbines in the Midwest ISO region have longer start-up times than they are physically capable of achieving. This can compel operators to commit slower-starting units further in advance of an anticipated condition, which inherently increases the inaccuracy and costs of such commitments. Ancillary service markets would provide financial incentives for suppliers to reduce their start-times for quick-starting gas turbines so that they qualify to provide operating reserves.

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-ante prices and market outcomes are the basis for the 5-minute dispatch instructions that are sent to each generator in the Midwest ISO. The ex-post prices are used for settlements and are calculated after the operating period based on the actual (rather than predicted) power flows and output.

For ex-post prices, only units that are flexible and following dispatch instructions may set prices. Hence, the units eligible to set ex-post prices can be different from in the ex-ante solution. Each flexible unit has a price at which a unit is assumed to offer energy in the ex-post market. This price is a function of the unit's bid curve, actual output and ex-ante price. Consistency between the ex-ante and ex-post prices is important for ensuring that suppliers have the incentive to follow the ex-ante dispatch instructions. Figure 41 shows the results of our evaluation of consistency between ex-post and ex-ante prices. This figure shows 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. The second metric indicates how large the differences are, regardless of the direction of the difference.

Figure 41: Ex-Ante and Ex-Post Price Differences
All Hours

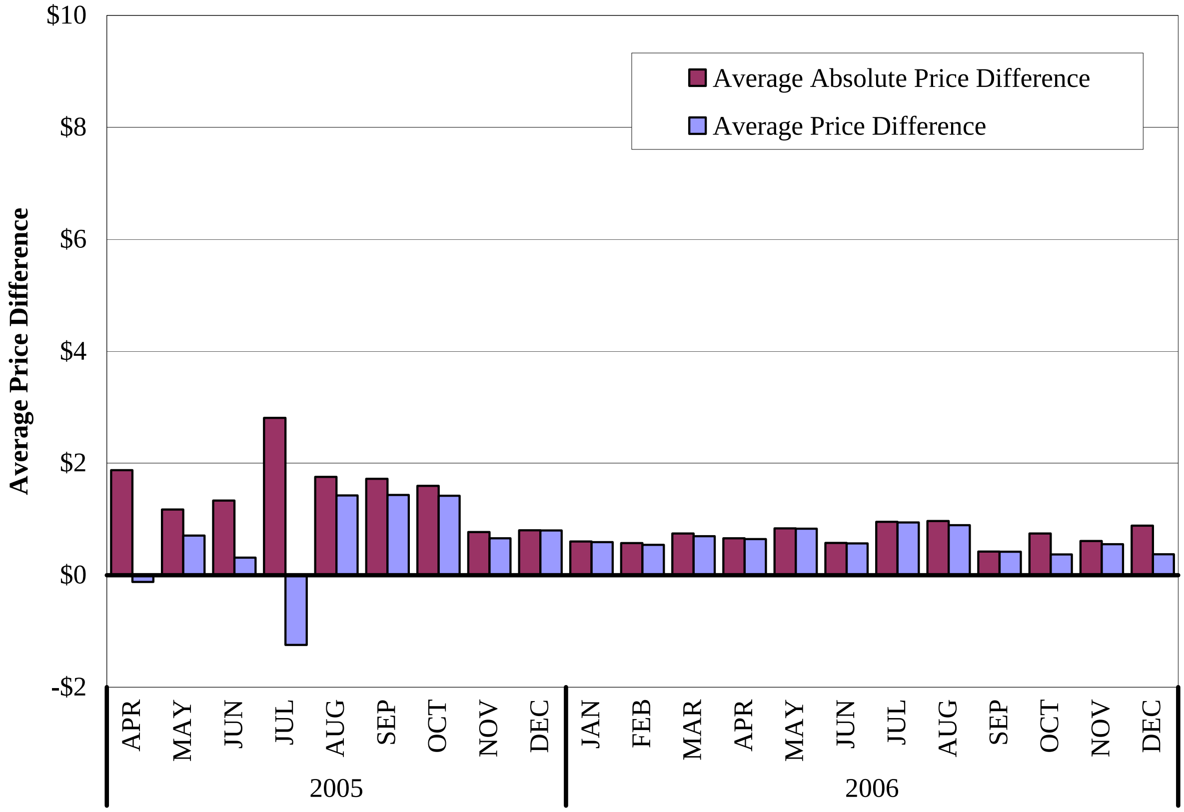
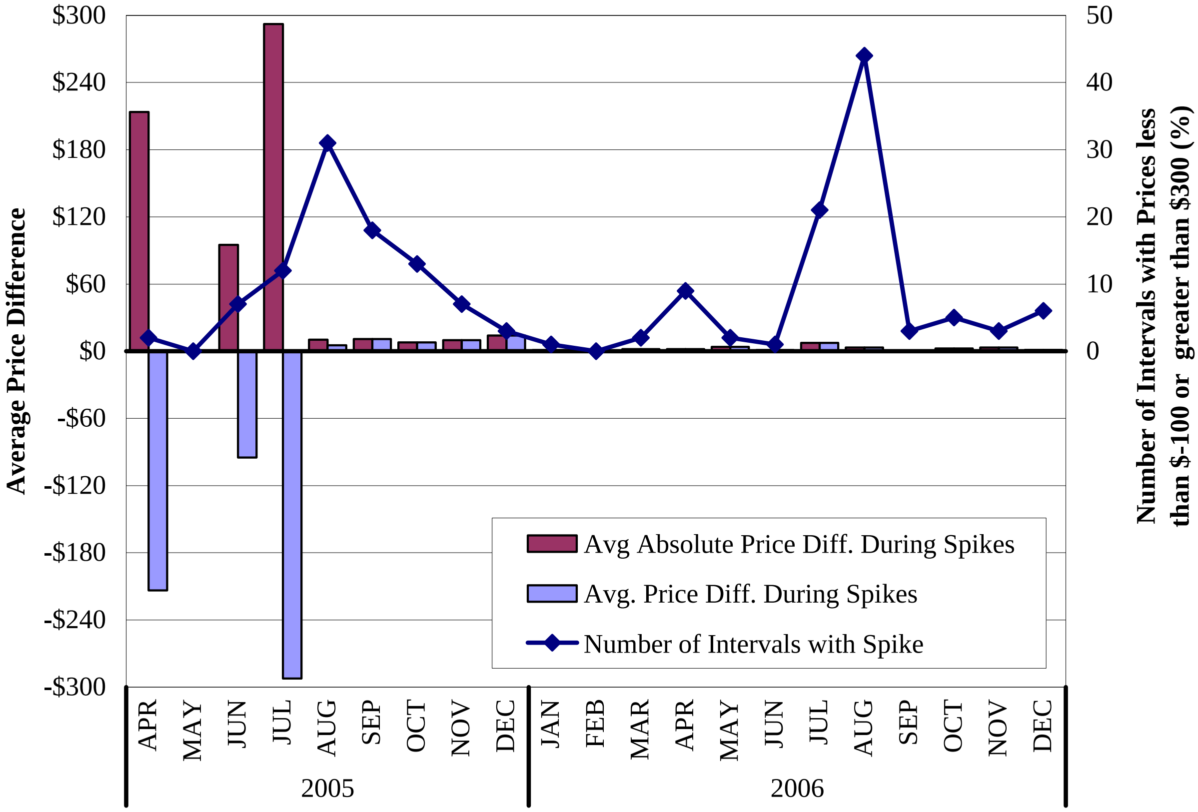


Figure 41 shows the average differences between the five minute ex post and ex-ante prices were relatively small. The typical hourly difference (the average absolute difference) was generally also small, with the exception of July 2005. Although the average differences between ex-post and ex-ante pricing have not been large, it is important to evaluate substantial differences during peak demand conditions or periods of extreme congestion. During these periods, generators may be asked to change production rapidly or dispatch very expensive output segments.

If ex-ante prices are inconsistent with ex-post prices during these conditions, generators can be harmed by following MISO's dispatch instructions. To evaluate this issue, our analysis in Figure 42 shows the average difference and the average absolute difference in hours and at locations with relatively extreme prices. For purposes of this analysis, extreme prices are defined as prices above $300 per MWh or lower than -$100 per MWh.

Figure 42: Ex-Ante and Ex-Post Price Differences
During Price Spike Events



This figure shows the differences between the ex-ante and ex-post prices that prevailed during ex-ante price spikes in the first four months of the Midwest ISO markets. In general, these occurred when relatively extreme congestion arose that caused prices at certain nodes to rise or fall sharply. The Midwest ISO made modifications in early August 2005 to the ex-post pricing methodology in order to improve the consistency between the ex-ante and ex-post prices. The figure shows that these changes were very effective in addressing the large differences that prevailed previously and that after July 2005, these differences were all but eliminated.

The ex-post pricing changes the Midwest ISO made were valuable because the ex-ante prices are, in theory, more efficient than ex-post prices. Ex-post pricing has been justified as a means to provide incentives for generators to follow the dispatch signal (because a resource that does not do so cannot set the price). However, it is does not efficiently provide such an incentive – it changes the price for all participants – including those following the dispatch instructions. In fact, large ex-post price differences can actually create a disincentive to follow dispatch instructions when a supplier believes that ex-post prices may be inconsistent with ex-ante prices. Uninstructed deviation penalties that applied only to generators that are over or under-producing are a much more efficient means to provide incentives for suppliers to follow dispatch instructions than ex-post pricing. The changes made by the Midwest ISO to the ex-post pricing model have resolved most of the largest inconsistencies with the ex-ante prices.

F. Market Outcomes Conclusions

In its second year, the Midwest ISO's real-time market performed well. Prices in the real-time market were substantially more volatile than in the day-ahead market, as expected. The nodal market accurately reflected the value of congestion in the Midwest – the most substantial congestion was into WUMS early in the first half of the year and into Minnesota in the second half of the year. 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, although this process was improved in 2006 versus 2005 and contributed to reduced RSG levels;
- The fact that prices do not always reflect the marginal value of energy when the system must rely on relatively inflexible peaking resources or demand response.

To improve the performance of the real-time market, we recommend the Midwest ISO:

(1) Implement the real-time ancillary services markets as soon as practicable. Ancillary services markets that are jointly optimized with energy will allow the market to more efficiently allocate resources between the two services and set efficient prices that reflect the economic trade-offs between reserves and energy.

(2) Develop a "look-ahead" capability in the real time that would commit quick-starting gas turbines and better manage ramp capability on slow-ramping units. The MISO has made operational improvements in its commitment of peaking resources, but the commitment of these units can be further improved by reliance on an economic commitment model. Allowing the market to commit and de-commit the turbines would reduce the out-of-

merit quantities, reduce RSG payments, and improve the ability of peaking resources to set the energy price.

(3) Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices. This is a difficult challenge because the market must distinguish between those turbines that would still be needed if they were more flexible versus those that would be ramped down to zero. This change would improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs.

(4) Develop demand response programs that will facilitate the development of additional demand response capability and allow these resources to set energy prices in the real-time market when they are called in a shortage. Additional demand response capability that is coordinated and managed by the Midwest ISO would improve reliability during shortage conditions. Assuming that the demand response resources can set the energy price at the value of their forgone consumption, the demand response would also improve price signals in the highest-demand hours. This is important for ensuring that the markets send efficient economic signals to develop and maintain adequate supply resources and develop additional demand response capability.

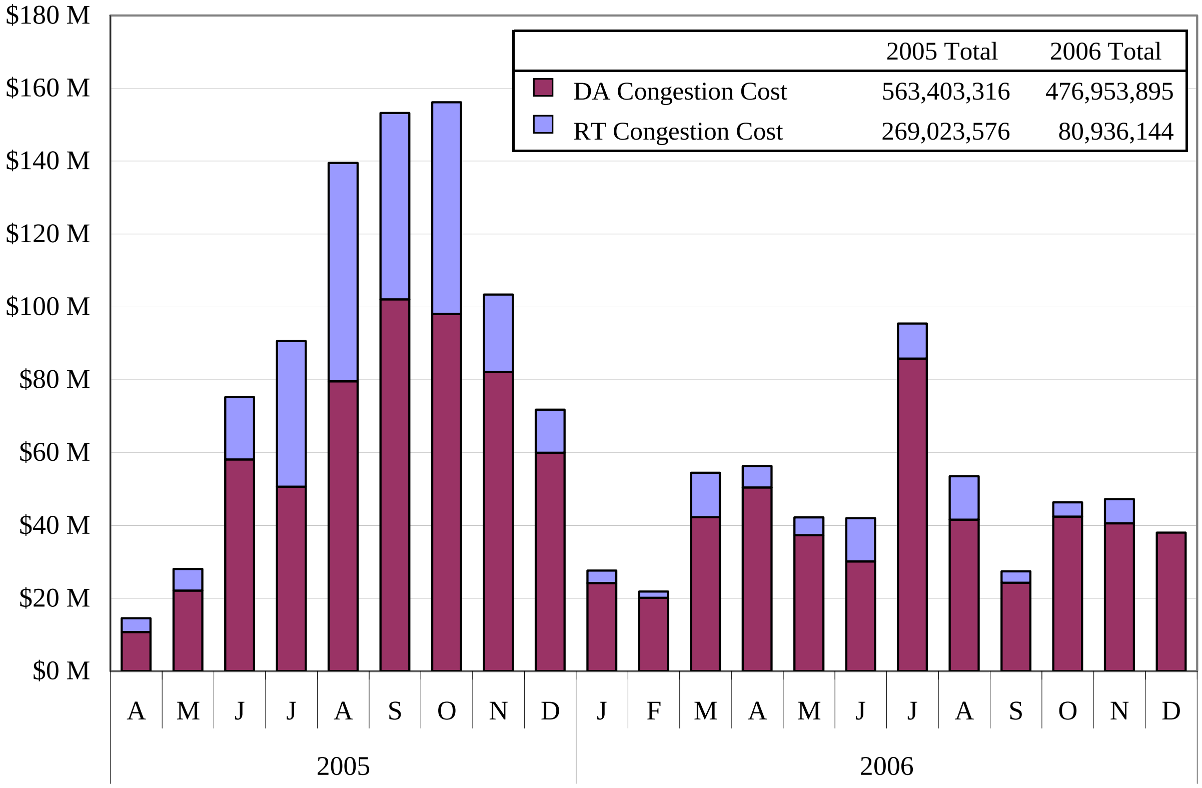
V. Transmission Congestion and Financial Transmission Rights

One of the primary functions of the Midwest ISO energy markets is to deliver the lowest cost supply to load given the limitations of the transmission network. The locational market structure in the Midwest ISO generally ensures that the transmission capability will be fully used and that the marginal value of energy will be reflected in the price at each location. When transmission capability is limiting such that higher-cost resources must be dispatched to serve the load (i.e., a transmission constraint is binding), the prices on either side of the transmission constraint will vary. This results in congestion costs being incurred that reflect the value of the transmission constraint. An efficient system will always have some congestion because transmission investment should only be made when the cost of the investment is less than the congestion cost. This section of the report evaluates congestion costs, FTR market results, and the Midwest ISO's management of congestion during 2006.

One of the principal benefits of the Midwest ISO energy markets is that they provide transparent economic signals regarding the costs of managing congestion on the transmission network. 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.

We begin this section by showing the congestion costs collected in the day-ahead and real-time markets. Figure 43 summarizes the total congestion costs on a monthly basis for 2005 and 2006. Congestion costs occur when higher-cost units must increase output on the constrained-side of a transmission interface (resulting in a higher locational price in the constrained area) and lower-cost units must decrease output on the unconstrained side of the interface (resulting in a lower locational price in the unconstrained area). The difference in prices across the interface represents the marginal value of the transmission capability between the two areas. When power is transferred across the interface, congestion costs are collected through the LMP market approximately equal to the difference in prices between the locations multiplied by the amount of the transfer. This occurs as a result of the fact that the 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).

Figure 43: Total Congestion Costs
April 2005 to December 2006



The total day-ahead congestion costs paid by market participants in the last nine months of 2005 were $563 million and the total real-time congestion costs were $269 million. Congestion costs for all 12 months of 2006 were significantly lower than in 2005, at $477 and $81 million in the day-ahead and real-time markets, respectively. In 2005, the congestion increased rapidly from the spring to the summer as higher loads and power flows throughout the Midwest resulted in higher congestion and gas prices contributed to higher costs in the Fall and Winter.

Congestion costs were considerably lower in 2006, primarily because lower gas prices contributed to lower congestion costs by reducing redispatch costs incurred to manage the congestion. Congestion on the North to South path into TVA also was greatly reduced in 2006.

Substantial congestion into TVA occurred in 2005, caused in large part by transmission service sold by PJM. However, this service is now being better coordinated with the Midwest ISO.

Figure 43 also shows that a large share of the reduction in total congestion costs was associated with a sharp reduction in real-time congestion. 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 generally sizable only when the transmission limits decrease from day ahead to real time or when loop flows from outside the Midwest ISO (that reduce the network capability available for the Midwest ISO) increase from the levels assumed in the day ahead. This is because the collections are associated only with deviations from the day-ahead use of the transmission. Like the settlements for load and generation, schedules in the day-ahead market are not settled again in real-time. Only increases or decreases from the day-ahead schedule are settled in the real-time market.

For example, if a transmission interface is fully scheduled in the day-ahead market and is congested (and the limit for the interface changes for the real-time market), no additional congestion costs will be collected in the real time. The value of the 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. Based on our review of the result in 2006, we conclude that the sizable reduction in congestion costs collected in the real-time market was due to improvements in the assumed loop flows that the Midwest ISO use in operating the day-ahead market.

A. Day-Ahead Congestion and FTR Obligations

The value of transmission capacity is reflected in the FTRs that are generally entitled to the congestion costs collected between the source and sink locations that define a given right. 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 congestion between the source and sink of the FTR.[6] Obligations for FTRs are paid with congestion revenues collected in the Midwest ISO day-ahead market. Surpluses and shortfalls are expected to be limited when the portfolio of FTRs held by participants generally matches the Midwest ISO power flows over the transmission system. However, when the FTR rights exceed the physical capability of the transmission system (or loop flows from activity outside of the Midwest ISO region use some of the transmission capability), the Midwest ISO may collect less day-ahead revenue than it owes to the FTR holders. Figure 44 compares monthly day-ahead congestion revenues to monthly FTR obligations. 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 44: Day-Ahead Congestion and Payments to FTR Holders

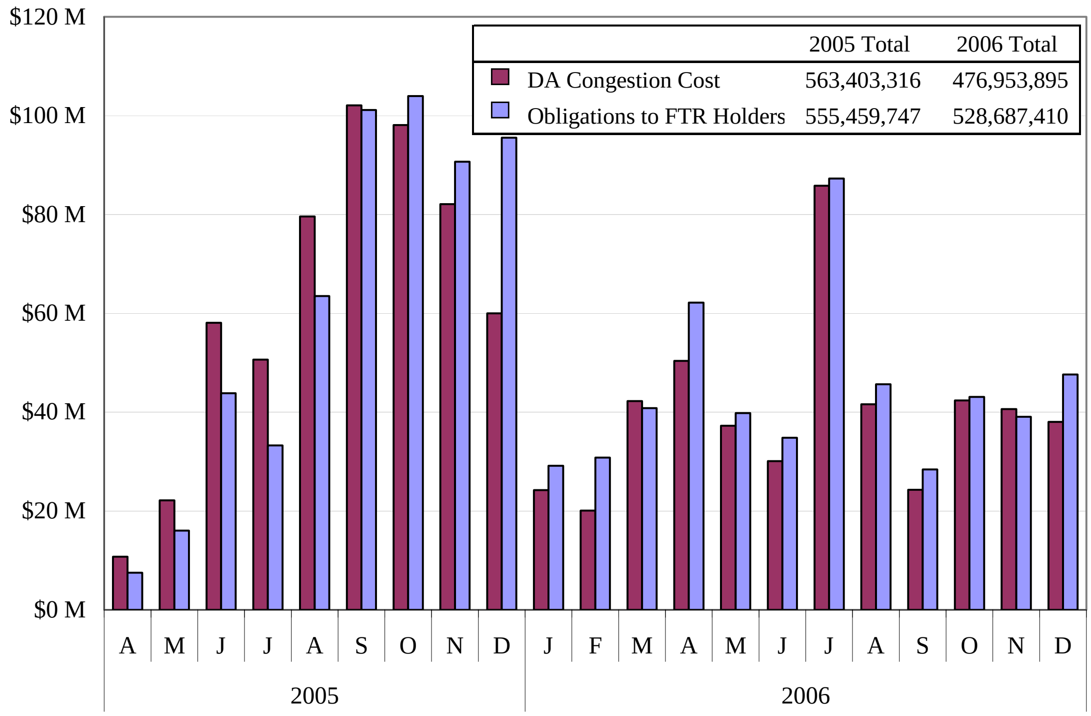


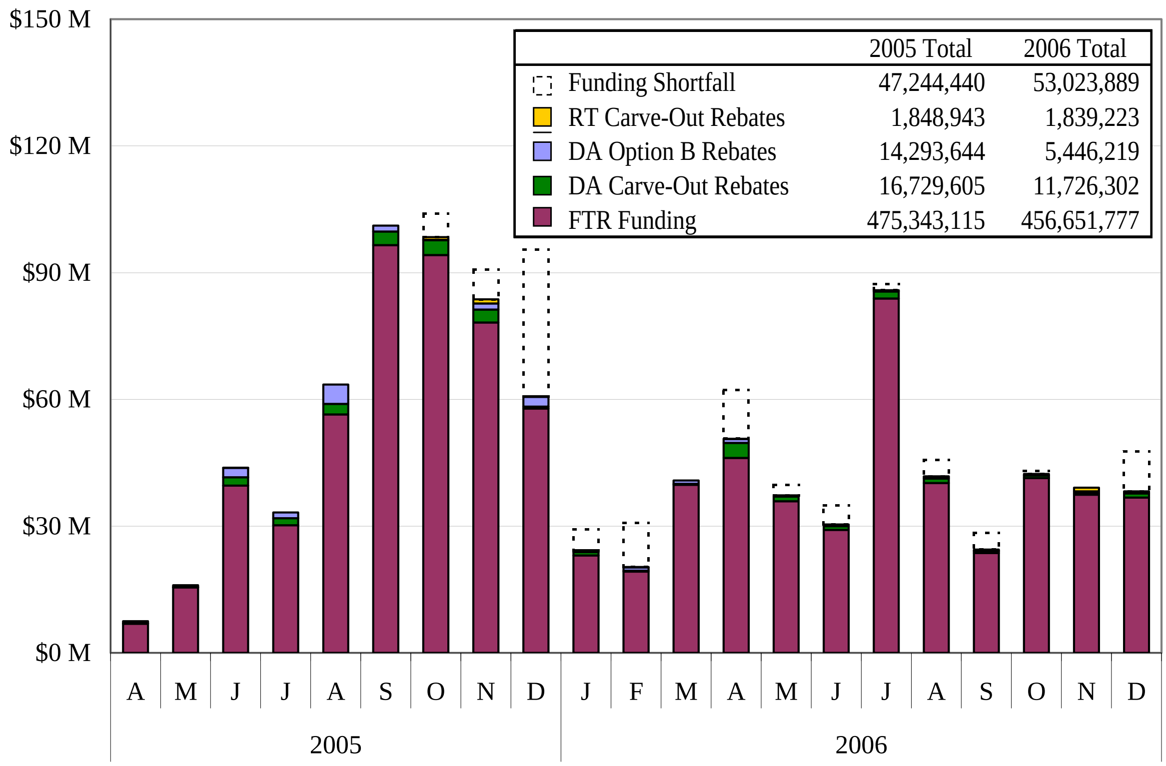
Figure 44 shows that FTR obligations exceeded total day-ahead congestion collections for the year. The opposite was true during 2005 when a large congestion surplus emerged during the first six months of Day 2 operations. Two main factors contributed to the shortfalls in 2006:

6 Footnote text: An FTR obligation can be in the "wrong" direction (counter flow) and can require a payment from the participant.

significant planned and unplanned transmission outages occurring in the day-ahead markets that were not modeled in FTR allocation and auction processes; and increasing loop flows late in the year that were modeled in day-ahead, but not fully reflected in the FTR modeling. Unanticipated loop-flow is a problem because the Midwest ISO collects no congestion revenue from entities that cause loop flow over its key interfaces. If the ISO allocates FTRs for the full capability on these interfaces, the loop flows will create an FTR revenue shortfall.

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 (i.e., "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 associated with the right. The rights include an alternative type of FTR with use-it-or-lose-it characteristics (Option B FTRs) and congestion "carve-outs". Figure 45 shows the monthly payments and obligations to FTR holders, including payments to FTR Option B and Carve-Out FTRs.

Figure 45: Payments to FTR Holders
2006: All Hours



	2005 Total	2006 Total
Funding Shortfall	47,244,440	53,023,889
RT Carve-Out Rebates	1,848,943	1,839,223
DA Option B Rebates	14,293,644	5,446,219
DA Carve-Out Rebates	16,729,605	11,726,302
FTR Funding	475,343,115	456,651,777

As shown in the figure, 96 percent of all payments were made to FTR holders (i.e. only four percent of payments were made to holders of other types of transmission rights) It is desirable to limit non-FTR rights on the system because these non-FTR rights can distort their holders' operating incentives and lead to a less efficient commitment and dispatch.

As noted above, the primary causes of the shortfall were differences in the transmission topology and loop flow assumptions in the day-ahead market and the FTR model. In particular, the ISO improved its assumptions regarding loop flows in the day-ahead market, which reduced the congestion revenues collected in the day-ahead market. Additionally, significant planned and unplanned outages reduced the transfer capability on key interfaces and increased the shortfall.

B. Value of Congestion in the Real-Time Market

This subsection evaluates the congestion patterns that occurred in the real-time market. In general, we focus on the value of the real-time congestion rather than the congestion costs collected in the real-time market that were discussed earlier in this section. Therefore, we have calculated the implied "value" of real-time congestion. The value of real-time congestion is equal to the marginal cost of the constraint (i.e., the shadow price) times the flow over the constraint in a given dispatch interval. Figure 46 shows the value of real-time congestion by region for all binding real-time constraints.

Figure 46 shows that most of the congestion occurred in the Central and East regions during the first nine months of 2006. During the last three months, congestion in the West region exceeded that of all other regions combined. Congestion values in the fall were impacted by localized congestion into Minnesota. This relatively high congestion in the West was caused by reduced imports from Manitoba, a series of events related to generation and transmission outages, as well as normal winter peaking of load in the northern areas. Figure 46 also shows that the average number of constraints that are binding at any point in time (i.e., during each interval). The average number of constraints typically binding in 2005 was 1.5 (peaking at 2.1 in September) versus only 1.1 in 2006.

Figure 46: Value of Real-Time Congestion by Coordination Region
April 2005 - December 2006

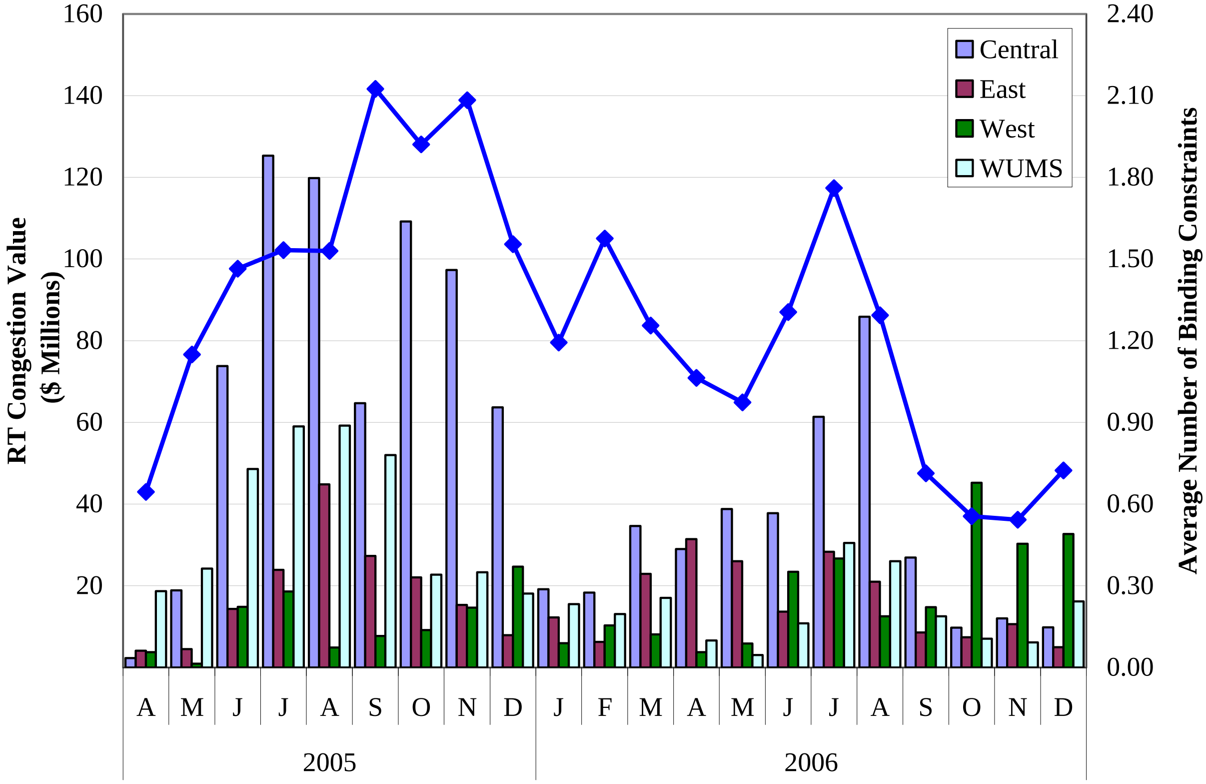
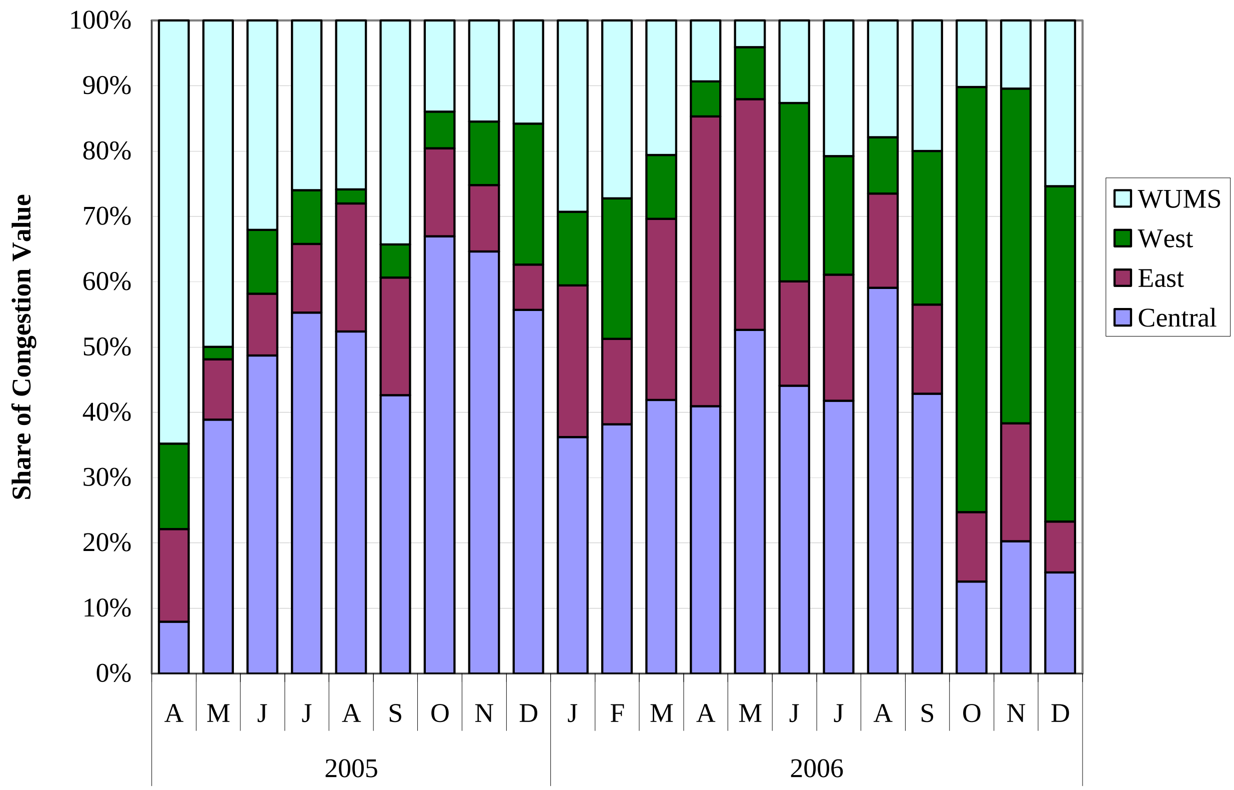


Figure 47 shows the share of congestion costs that are incurred in each region, which more readily illustrates the change in congestion patterns over time. As Day 2 operations commenced, most of the congestion in MISO occurred in WUMS. By June 2005, voltage problems in Kentucky and exports to TVA led the Central region to overtake WUMS with the highest share of congestion costs. Throughout the rest of 2005 and the first three quarters of 2006, this continued to be the case. As Manitoba hydro imports declined in the fall of 2006, the West became the most congested region. The West continues to be the most congested region in MISO in 2007, even after the designation of the Minnesota NCA.

Figure 47: Share of Real-Time Congestion by Region



To better identify the real-time sources of congestion, we have also calculated the value of congestion by type of constraint in our next analysis. Figure 48 shows these results for the following categories constraints:

- Constraints internal to the Midwest ISO that are not coordinated with PJM (non-market-to-market constraints);
- The Midwest ISO constraints that are coordinated with PJM (Midwest ISO market-to-market constraints);[7]
- The PJM constraints that are coordinated with the Midwest ISO (PJM market-to-market constraints), and
- Constraints located on other systems that the Midwest ISO must redispatch to relieve when a TLR is called (external constraints).

7 All Midwest ISO internal constraints are subject to a series of tests under the JOA with PJM to determine whether it should be defined as a market-to-market constraint. The Midwest ISO market-to-market constraints are the subset of internal constraints (including the Midwest ISO controlled tie lines with PJM) which have met these tests. PJM market-to-market constraints are of course PJM internal constraints that have met the tests under the JOA.

Figure 48: Value of Real-Time Congestion by Type of Constraint
2006

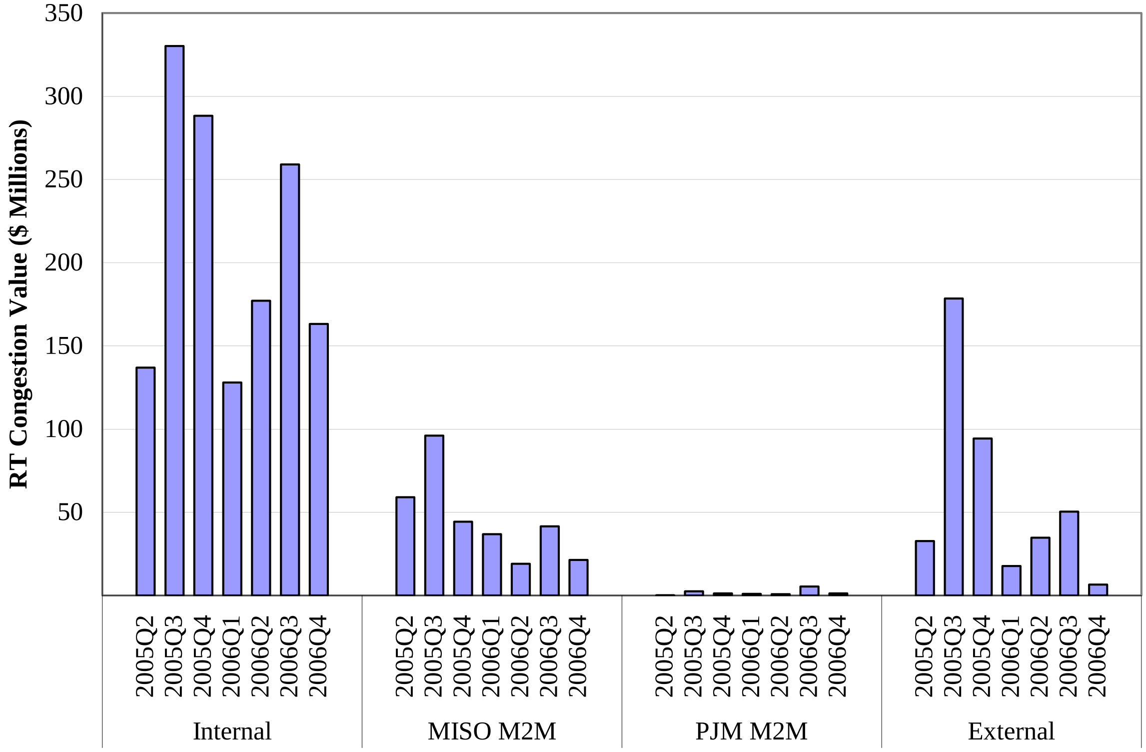


Figure 48 shows that most of the congestion occurred on the Midwest ISO internal constraints (including the Midwest ISO market-to-market constraints). Together, the Midwest ISO constraints (internal and market-to-market) represent nearly 82 percent of the congestion value. It is notable that a sizeable portion of this congestion was on the market-to-market constraints, which indicates the importance of the market-to-market coordination under the JOA with PJM.

Although the congestion on external congestion was significant, it was associated with a very small number of constraints. In fact, the top eight external constraints account for 60 percent of external congestion. Total congestion on these constraints decreased substantially, in part, because PJM is now coordinating sale of export service to TVA that had contributed to substantial congestion on the Midwest ISO system in 2005. In addition, many constraints deemed internal in 2005 are now classified as external due to the withdrawal of LG&E from the Midwest ISO. This change adds to the amount of external congestion measured in 2006.

C. TLR Events

The Midwest ISO continues to use transmission line-loading relief ("TLRs") procedures and the NERC Interchange Distribution Calculator ("IDC") to support Day 2 operations, when required. The TLR process is a much less efficient and less controllable means to reduce the flow over a given transmission facility than economically redispatching generation in the area.

Prior to Day 2 markets, virtually all of the congestion management for Midwest ISO transmission facilities was accomplished by invoking the TLR procedures. When a constraint is binding under the Day 2 markets, the flow over the constrained transmission facility is generally managed by economically redispatching generation through the real-time market. However, since external entities contribute to the flows over the internal transmission facilities, a TLR is invoked when an internal constraint is binding to ensure that the external parties contribute to reducing the flow over the constrained facility. To show where the constraints have occurred that have resulted in TLRs, Figure 49 shows the quantity of TLRs called between 2004 and 2006 for the MISO sub-regions.

Figure 49: TLR Events by Duration
2004 to 2006

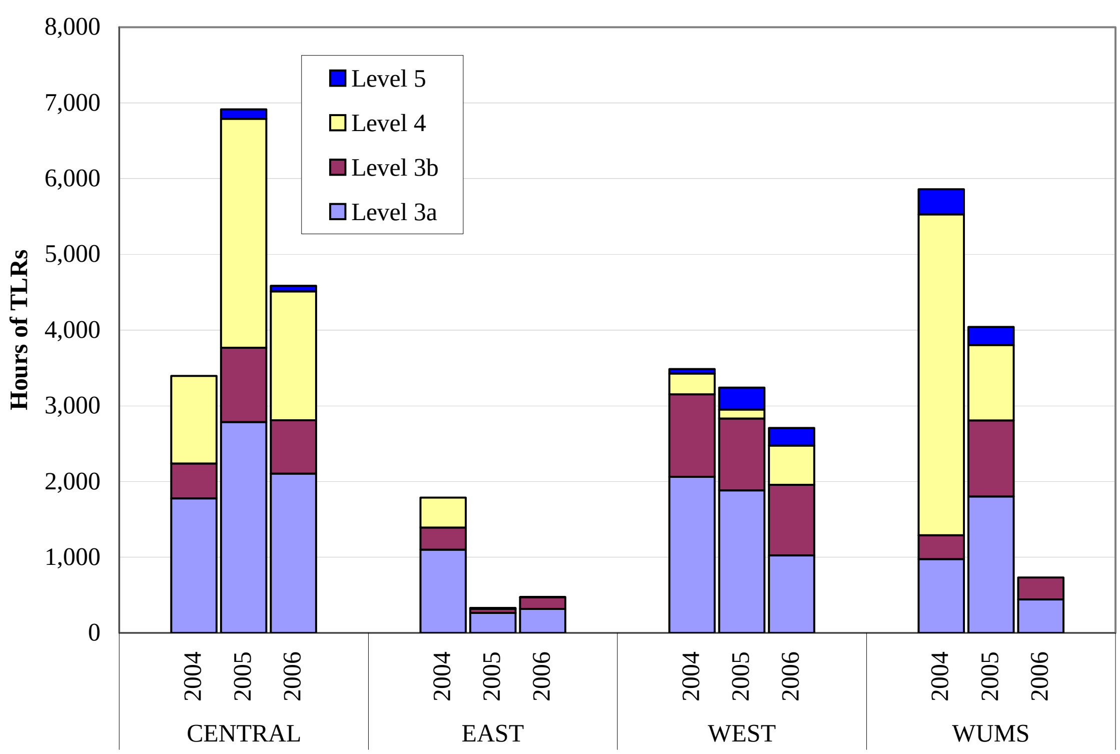


Figure 49 shows that TLR levels have declined in all regions except the Central region since the start of the Day 2 markets. TLRs called on MISO flowgates (level 3 and above) still account for 54 percent of all TLRs called in the Eastern Interconnect.

The implementation of the markets was not expected to reduce TLR calls substantially. When a constraint is binding in the MISO energy market, it invokes the TLR procedures to ensure others outside of the MISO that contribute to the congestion assist in relieving it. Although the significant quantities of TLRs are still called, the reliance on economic redispatch for managing congestion has increased substantially. Curtailments were 76 percent lower overall in 2005 than in 2004. Curtailments during the summer, which are generally larger in magnitude, decreased by 70 percent in 2005 compared to 2004.

The figure above also shows a spike in TLR activity in 2005 due primarily to increased North-to-South congestion related to service sold by PJM to TVA that was not coordinated under the market-to-market provisions. Steps have been taken to manage this service better. Level 4 TLRs have been eliminated in WUMS because, prior to the Midwest ISO markets, American Transmission Company ("ATC") redispatched generation when level 4 TLRs were called. This redispatch is now done through the MISO energy market.

D. Congestion Manageability

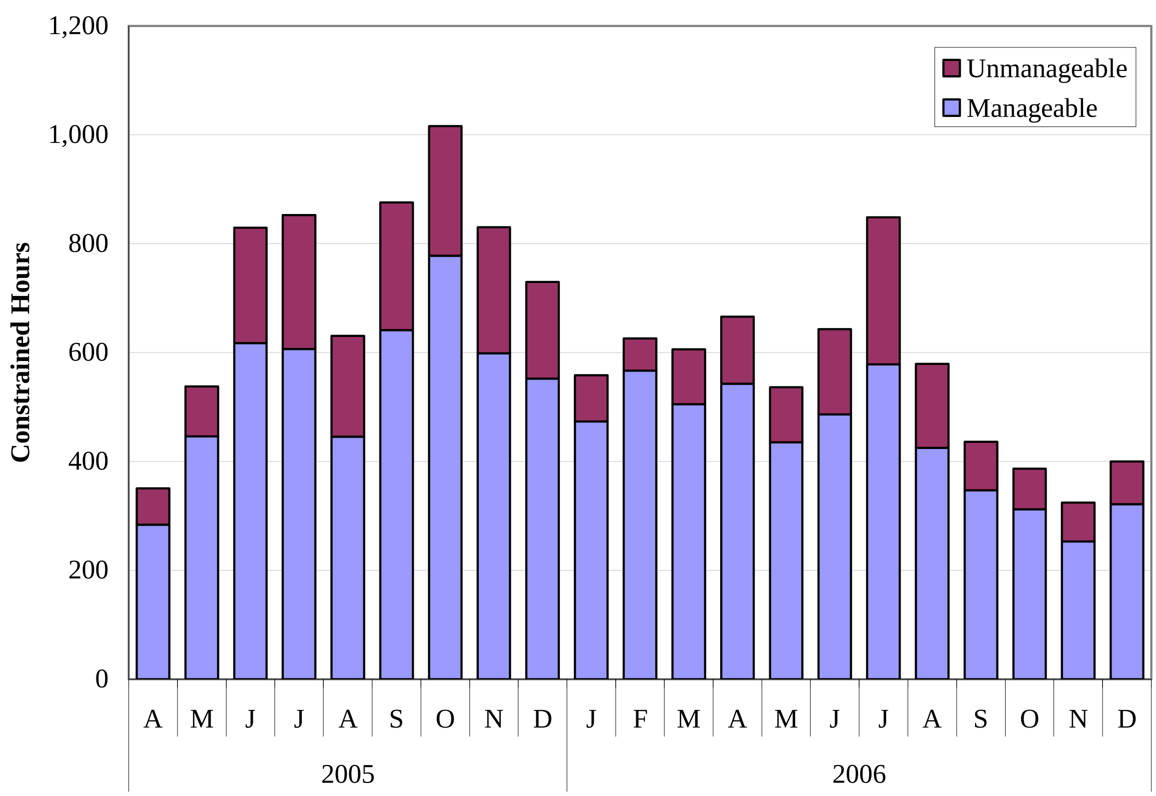
Congestion management is one of the most important activities of the Midwest ISO. In real-time the Midwest ISO is monitoring thousands of potential constraints throughout the market region. As these constraints approach their limit (or if they are anticipated to do so) in real-time, they are "activated" 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 transmission limits while minimizing overall production costs. Because this process is integral to the determination of locational prices and overall costs in the Midwest, any evaluation of the performance of the market should include an assessment of this process.

A real-time LMP-based energy market will redispatch generation to manage binding transmission constraints on the network. However, constraints can be difficult to manage if the available redispatch capability of the generators that affect the flow on the constraint is limited.

The available redispatch capability is reduced when effective generators are not online, when their flexibility is reduced (i.e., narrow EcoMax to EcoMin range or low ramp rate), or when the generators are already at their limit (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 5-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. 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 a reliability concern, it is nonetheless of interest in examining the Midwest ISO's congestion management. Figure 50 shows the frequency with which constraints were unmanageable in each month.

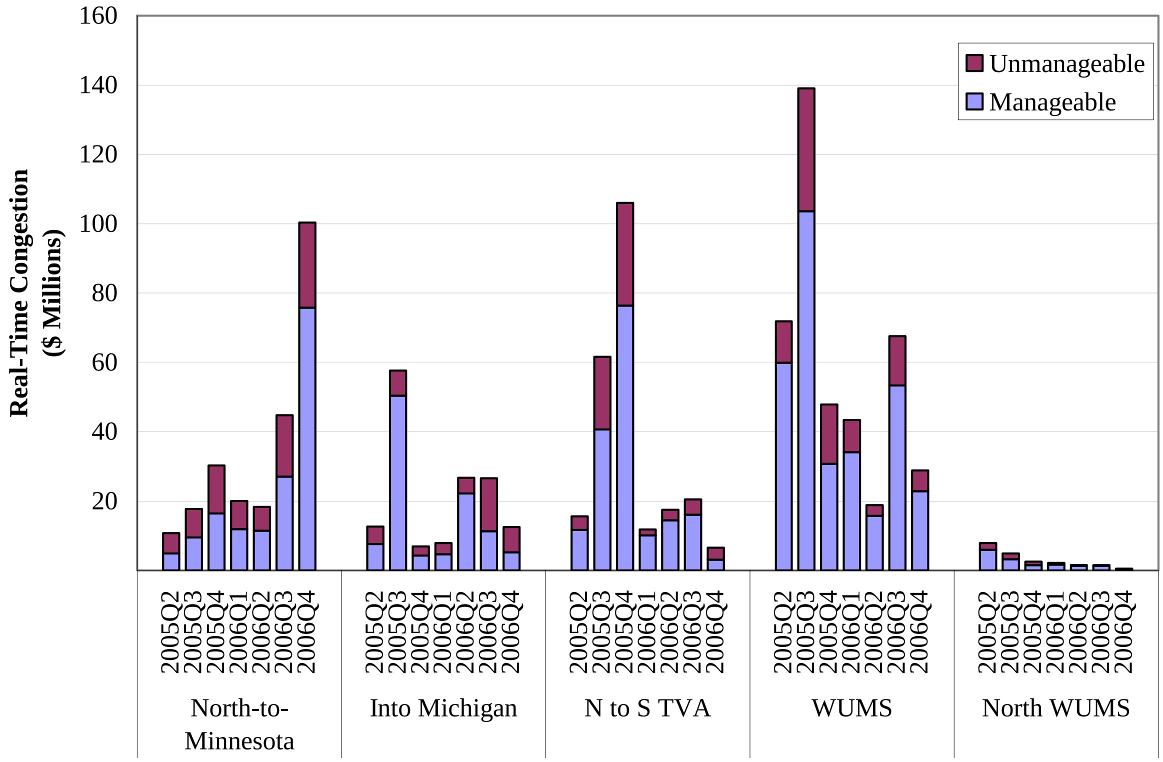
Figure 50: Congestion and Manageability
April 2005 through December 2006



Overall, 75 percent of the congestion was manageable on a 5-minute basis in 2005 and 80 percent in 2006. We anticipate that manageability will improve after the Price Volatility Make Whole Payment provision is in place because this provision will promote increased offer flexibility. The impact of inflexible supply offers on manageability is evaluated later in this section.

The next analysis shows the share of the congestion on selected interfaces that was manageable. The purpose of this analysis, which is shown in Figure 51, is to show how the manageability of congestion varies at different locations.

Figure 51: Value of Real-Time Congestion by Path



This figure shows that the highest-value congestion was on the interfaces into the WUMS area, as expected. The unmanageable congestion into this area in 2005 was caused, in large part, by generator inflexibility (inflated EcoMin levels on generators that cause power flows to increase over the constraint). During 2005, this inflexibility often resulted in negative real-time prices in Minnesota. More recently, manageability of congestion into WUMS has improved due to increased generator flexibility and reduced flows from Manitoba Hydro across the western interfaces into WUMS.

Congestion declined in 2006 compared with 2005, with the exception of along the North-to-Minnesota path. Nearly 20 percent of the congestion was unmanageable in 2006 on this path. As total congestion along this path increased, the unmanageable share declined. The increased frequency of binding constraints along this path resulted in the designation of the Minnesota NCA.

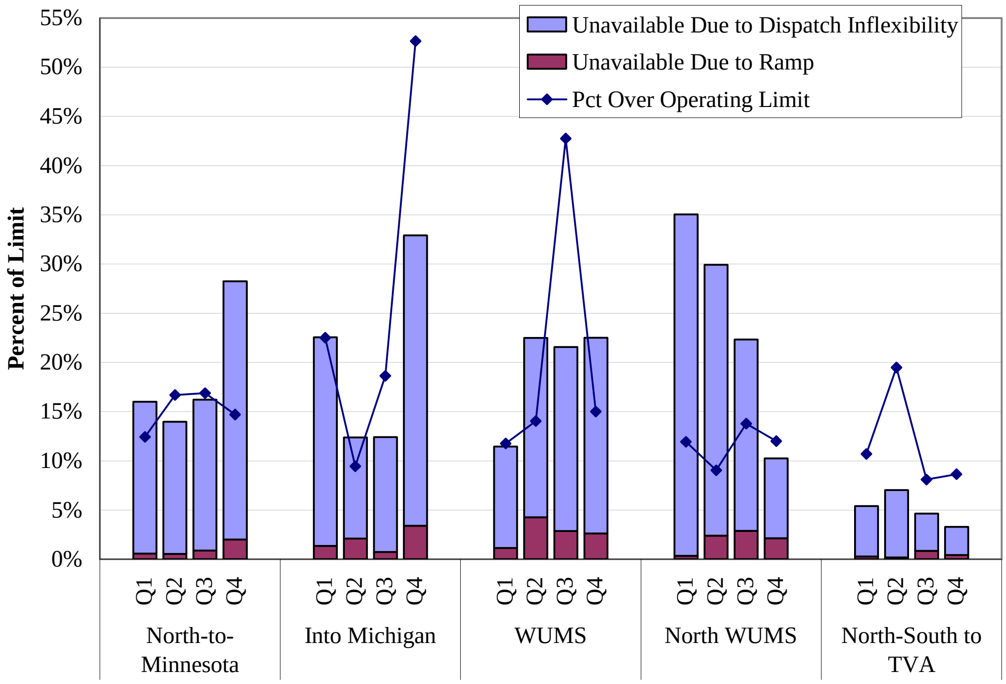
Our next analysis evaluates two components of suppliers' offer patterns that contribute to the unmanageability of transmission constraints. The first is the submission of inflexible dispatch parameters, which reduces redispatch opportunities from the market model. When a participant sets EcoMin levels much higher than the physical minimum output levels (i.e., prevents the market model dispatch 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 limits caused by a participant setting its ramp rate limits at a much slower level 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 through the market.[8]

Figure 52 shows our estimates of the amount of congestion relief (capability to reduce the flow on a constraint) that was unavailable due to each of these factors. To show how significant the unavailable relief quantities are to the market, the figure also shows the average percentage that the flow was over each constraint's limit when it was deemed unmanageable.

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

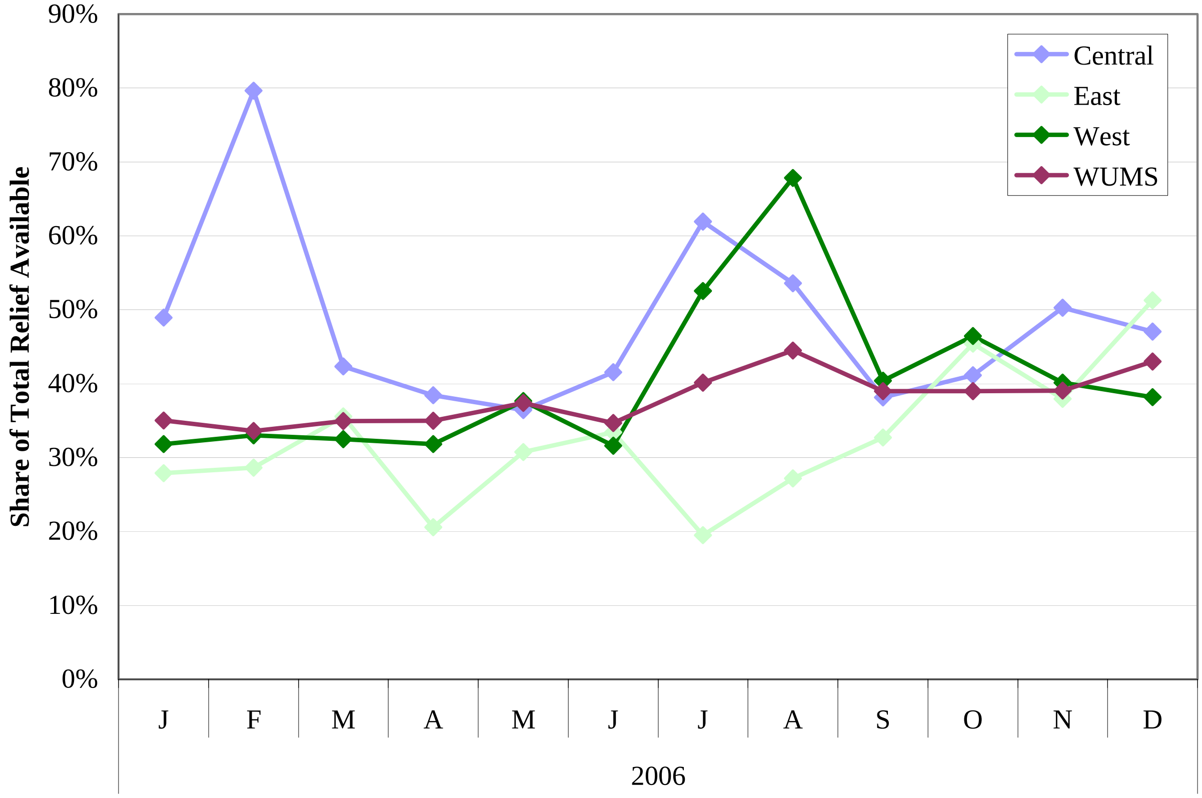
Figure 52: Congestion Relief Unavailable Due to Offer Parameters
Selected Paths



The results show that most of the time the congestion relief quantity that could have been available physically would have been sufficient to manage the congestion, except on the North-South to TVA path.

Finally, to illustrate how much relief is being withheld due to generators' inflexibility, we show the available congestion relief quantities as a percentage of the total relief that could have been provided by reducing the output of the generators on the unconstrained side of binding transmission constraints in the region in Figure 53. We refer to this as "decremental relief" because it is achieved by decrementing the generation.

Figure 53: Decremental Relief Quantities Offered by Region
April - December 2006



The figure shows the effects of generator inflexibility by showing the ratio of offered decremental relief (ability to reduce network flows by reducing a unit's output) to the relief that could have been offered for binding constraints in the Midwest ISO. In all regions, the share of relief available is trending upward. By December 2006, however, all regions offered less than 52 percent of the offer flexibility that might be technically feasible on internal and MISO coordinated market-to-market flowgates. We attribute the inflexibility to a number of reasons.

- In some cases, the reduced flexibility can be justifiable based on technical or reliability concerns.
- Inexperience with the market has led some participants to fail to recognize that they will increase their profit by reducing their output to manage congestion – some participants erroneously believe that forcing their resources to run at their day-ahead schedule is a profitable or rational strategy.

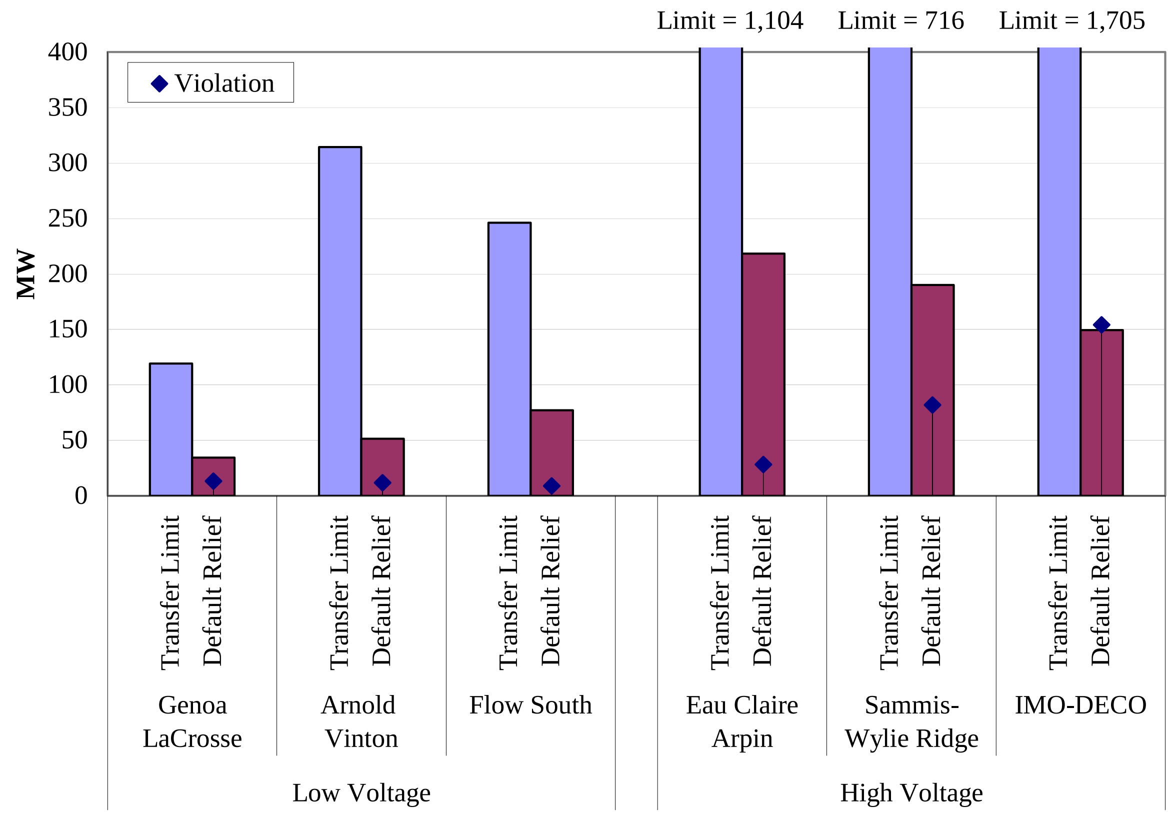
- Some participants may face incentives that differ from the profit-maximizing incentives of most businesses. In particular, regulated entities that will not retain a significant portion of the profit earned by being responsive to market signals may rationally adopt other operating strategies, such as a “risk minimizing” strategy of operating at a fixed output level.
- Some participants may be concerned that responding to dispatch signals during periods of high price volatility could sometimes reduce their profit – this is being addressed through the Price Volatility Make Whole Payment.

In 2005, a certain supplier’s inflexibility led to severe congestion. We investigated this conduct as market manipulation and referred it to FERC for enforcement. However, there were no circumstances warranting a referral to FERC in 2006 associated with inflexibility.

In addition to participants’ contribution to the instances of unmanageable congestion, a parameter in the Midwest ISO’s real-time market software also contributes to these instances. This parameter prevents units with a small effect on a constraint from being redispatched. Currently in the real-time market, units with generation shift factors less than 2 percent (or greater than -2 percent) are not redispatched.

A generation shift factor is the amount by which the flow on a transmission facility will change when the output of a generator increases. The +/- 2% GSF cutoff parameter is set to reduce the amount of data that must be produced and passed among the real-time systems. In general, all units are considered in the day-ahead market. Figure 54 shows the quantity of congestion relief that is eliminated by this parameter on selected constraints. For comparison purposes, the figure also shows each constraint’s limit and average violation when it is unmanageable.

Figure 54: Potentially Available Congestion Relief
Selected Paths



We calculated the relief quantities based on a planning case for September. The additional relief on each constraint was calculated by raising any excluded unit's output to its maximum or reducing any excluded unit's output to its minimum. The results show that the additional relief available by lowering the GSF cutoff parameter is generally larger than the average violations on the constraints sampled. This effect of the GSF cutoff parameter is particularly large for low-voltage constraints. This is the case because GSFs are generally small and less widely distributed for low voltage constraints – hence, the parameter tends to have a larger effect.

We have recommended to the Midwest ISO that it reduce this parameter as much as feasible for the generator nodes in its real-time market. The Midwest ISO has begun the work necessary to modify and test reduced levels for the GSF cutoff parameter.

Finally, we have evaluated the results produced by the relaxation algorithm that the Midwest ISO uses when a constraint is unmanageable. This algorithm increases the limits for unmanageable constraints for pricing purposes. Our evaluation indicates that this algorithm frequently produces an inefficiently low shadow price for the constraint, preventing the LMPs from fully reflecting the value of the constraint. To address this concern, we recommend the Midwest ISO discontinue use of the relaxation algorithm and set prices based on the constraint penalty factor. When a constraint cannot be resolved at a marginal cost less than the penalty factor, the value of the constraint must be higher than the penalty factor. To the extent that the relaxation algorithm determines a lower shadow price, therefore, it is an inaccurate reflection of the true value of the constraint. The Midwest ISO is investigating the software changes that would be necessary to implement this recommendation.

E. FTR Auction Prices and Congestion

In addition to an energy market, the Midwest ISO also administers a market for FTRs. FTRs are allocated to market participants based upon physical transmission rights on an annual and monthly basis. Additional FTRs are auctioned also on an annual and monthly basis. The next analysis evaluates the results of the FTR auctions, which should efficiently forecast future congestion costs if they are liquid and well functioning. It compares the average values in the monthly FTR auctions to the values of day-ahead congestion that are payable to the FTR holders. All the values shown in the following six figures are computed relative to Cinergy Hub to provide a fixed reference point. Additionally, more FTRs per month are purchased to and from the Cinergy Hub than any other node.

Figure 55 and Figure 56 show these values for WUMS in peak and off-peak hours. Compared to 2005, there was less day-ahead congestion in 2006 into WUMS. The FTR values reflect this change. Congestion was less predictable and the convergence was not as good overall in 2006. The convergence of FTRs was particularly poor during March through May when congestion into North WUMS caused negative congestion in WUMS. July also had relatively poor convergence due to high loads and the outage of the Forbes-Dorsey line. In the August to December period, convergence improved as congestion exceeded the FTR clearing price by less than \$600/MW for the peak hours and less than \$450/MW in the off-peak hours.

Figure 55: Comparison of FTR Auction Prices and Congestion Value
WUMS Area: Peak Hours

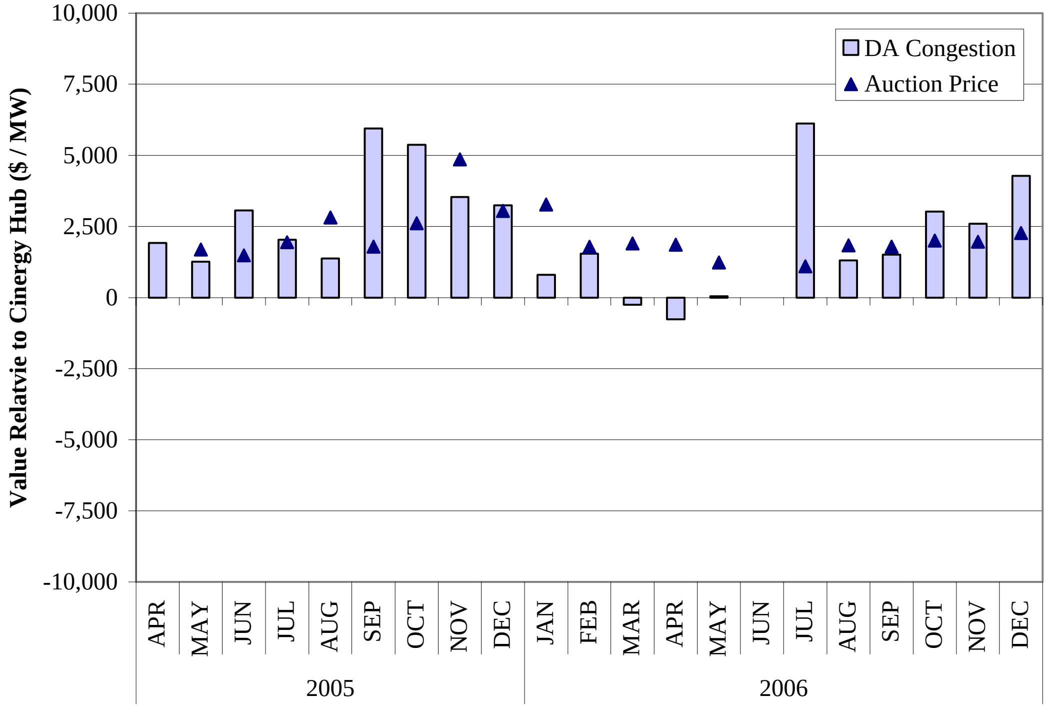
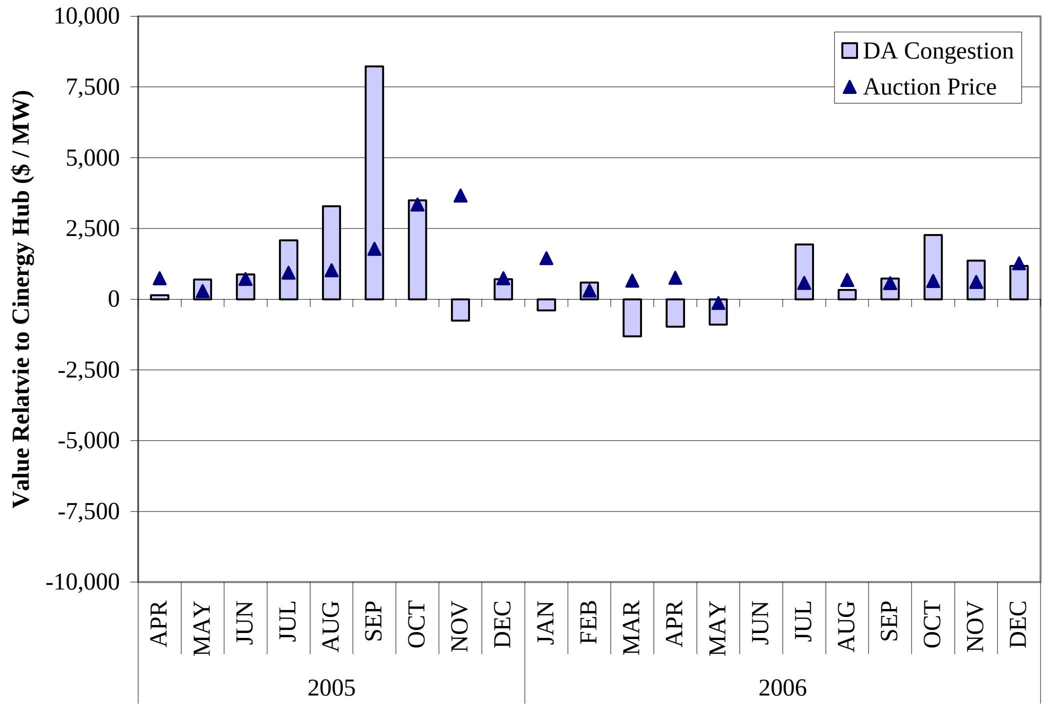


Figure 56: Comparison of FTR Auction Prices and Congestion Value
WUMS Area: Off-Peak Hours



The congestion and FTR results for the Minnesota Hub have been volatile throughout Day 2 operations. The Minnesota Hub has experienced the largest negative congestion (nearly -$10,000/MW during off-peak hours of August 2005) and the largest positive congestion (nearly $10,000/MW during peak hours of July in 2006). The negative congestion in 2005 was due to congestion into WUMS that was often difficult to manage, particularly in off-peak hours. Figures 57 and 58 show these congestion patterns and the associated FTR prices for Minnesota.

Figure 57: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub: Peak Hours

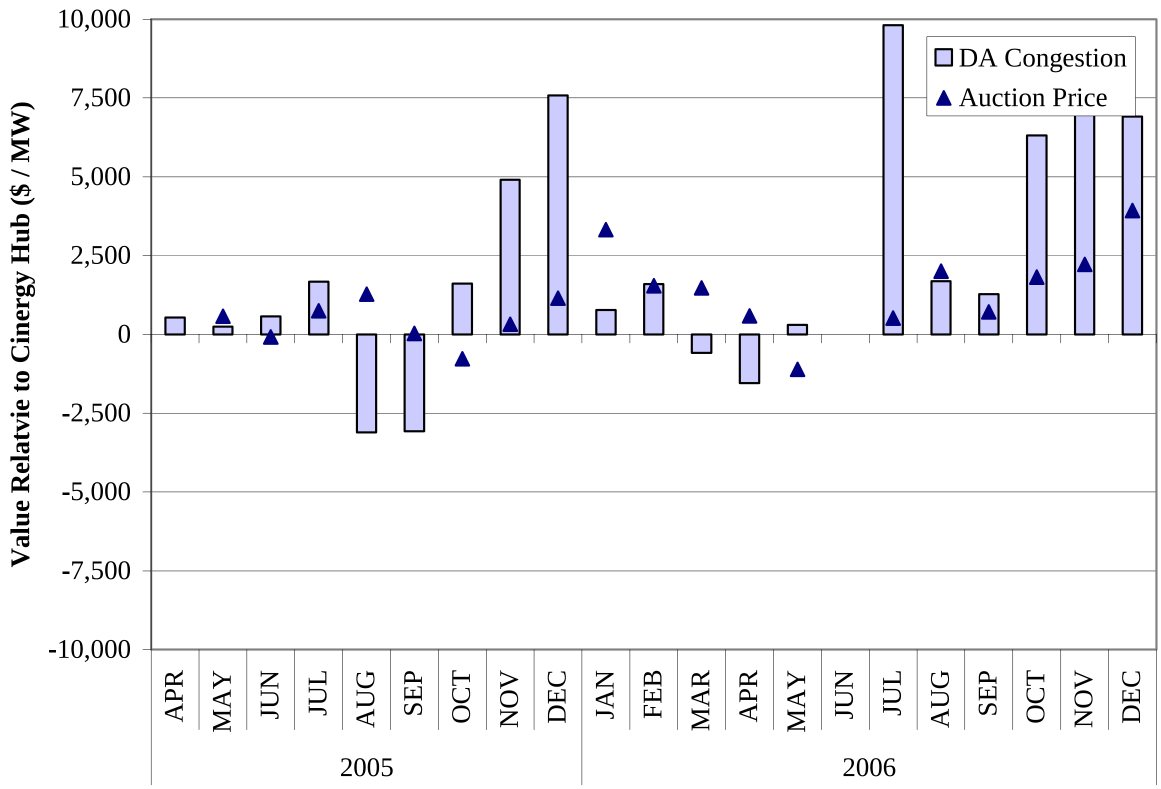


Figure 57 shows that congestion reversed direction (from negative to positive) in the summer 2006 due to increased south-to-north constraints into Minnesota. July 2006 shows substantial congestion that was due to high-loads, transmission outages in mid and late-July, and reduced imports over the Manitoba Hydro interface. Both figures show that FTR prices responded to changes in congestion patterns with a lag as one would expect (since FTRs are sold prior to the month in which the congestion occurs) and that convergence was not as good for Minnesota due, in part, to the fact that the congestion is more volatile and less predictable.

Figure 58: Comparison of FTR Auction Prices and Congestion Value
Minnesota Hub: Off-Peak Hours

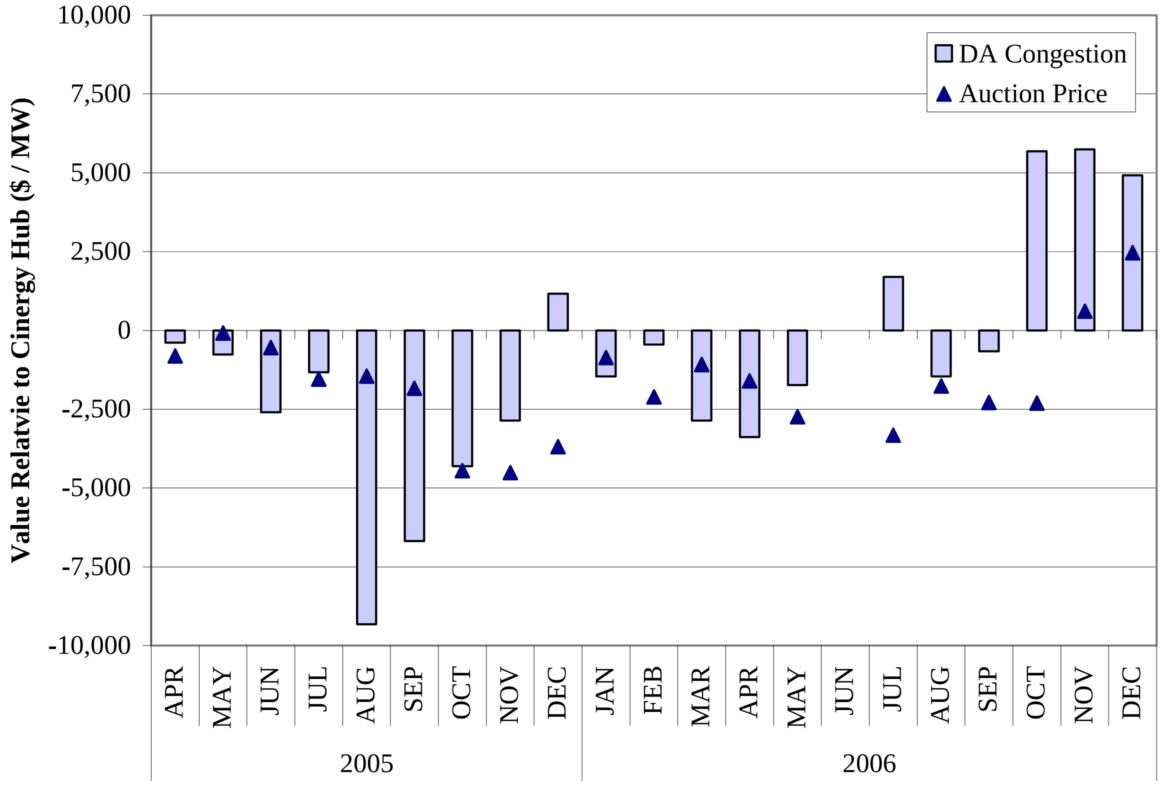


Figure 58 shows that the negative congestion subsided in 2006 as some additional dispatch flexibility was provided. The positive congestion that was prevalent in the peak hours late in 2006 occurred in the off-peak hours as well. The final two figures in this series show these results for the Michigan hub

As shown in Figure 59 and Figure 60, congestion in Michigan was very low in 2005 and even lower in 2006. The little congestion that occurred was consistent and FTR prices reflected congestion reasonably well throughout 2006.

Figure 59: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub: Peak Hours

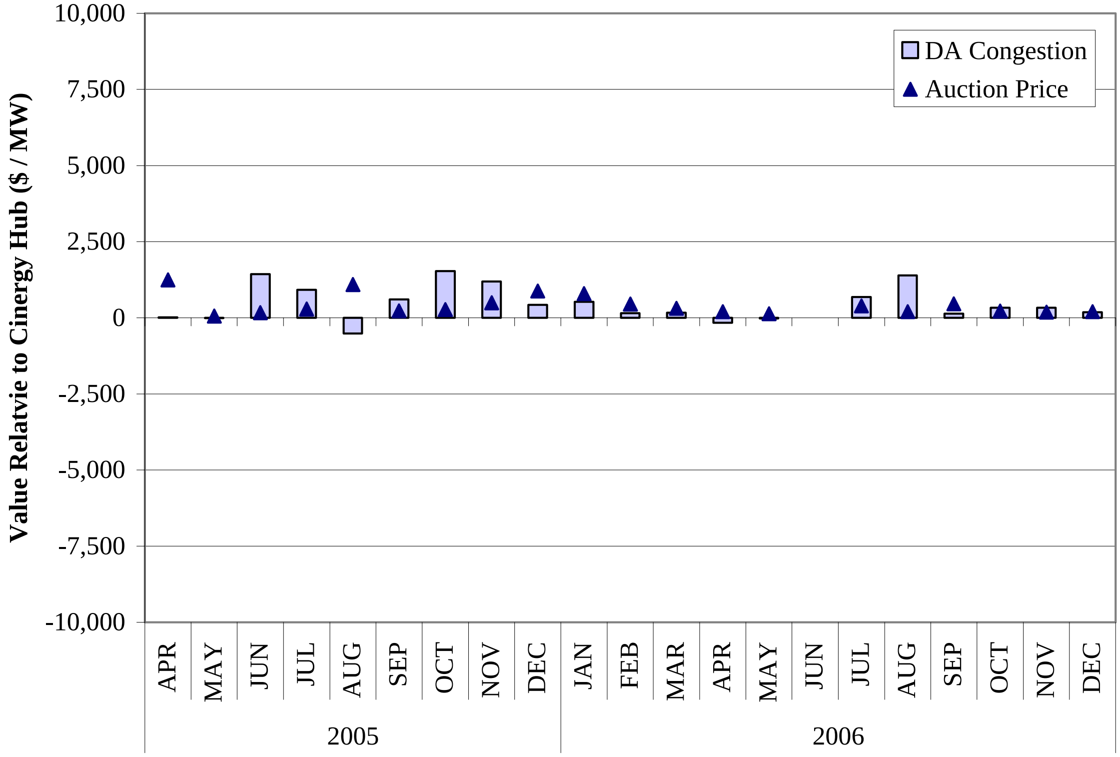
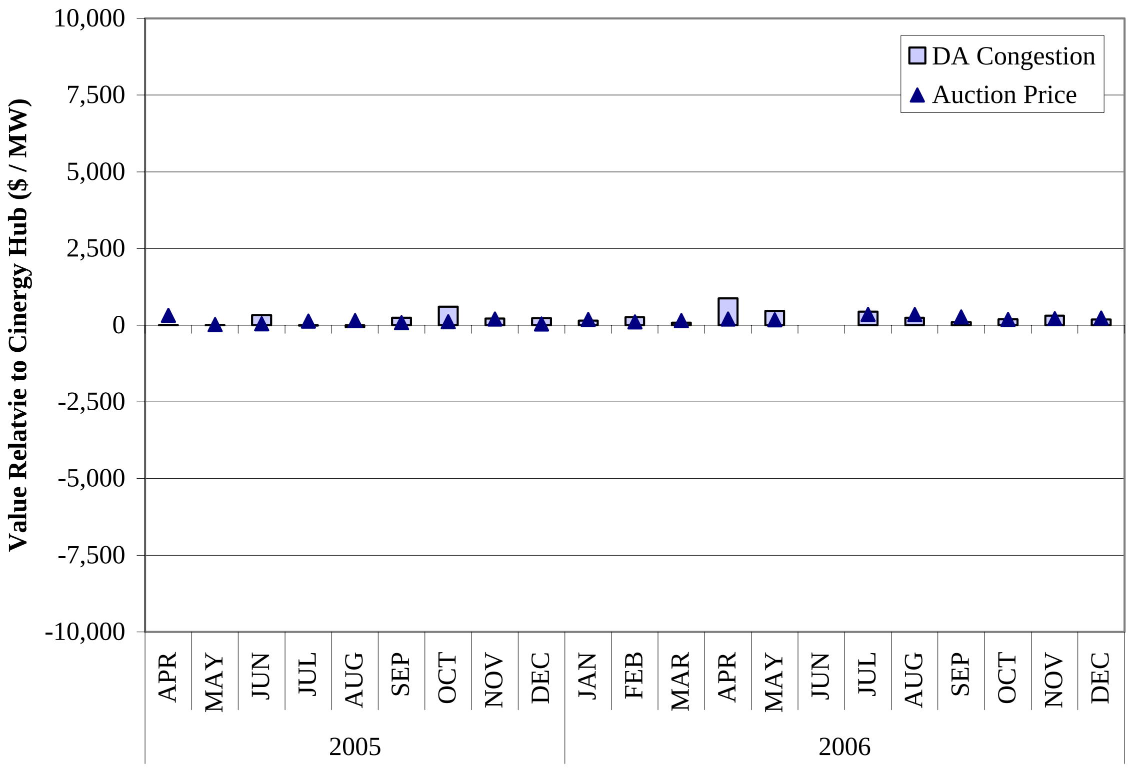


Figure 60: Comparison of FTR Auction Prices and Congestion Value
Michigan Hub: Off-Peak Hours



VI. Competitive Assessment

This section assesses the competitive structure and performance of the Midwest ISO markets during 2006. This type of assessment is particularly important for LMP markets. While LMP markets increase overall system efficiency, they can provide incentives for the localized exercise of market power in congested areas. The assessment includes structural analyses of the market, as well as an evaluation of participant conduct during the year.

A. Market Structure

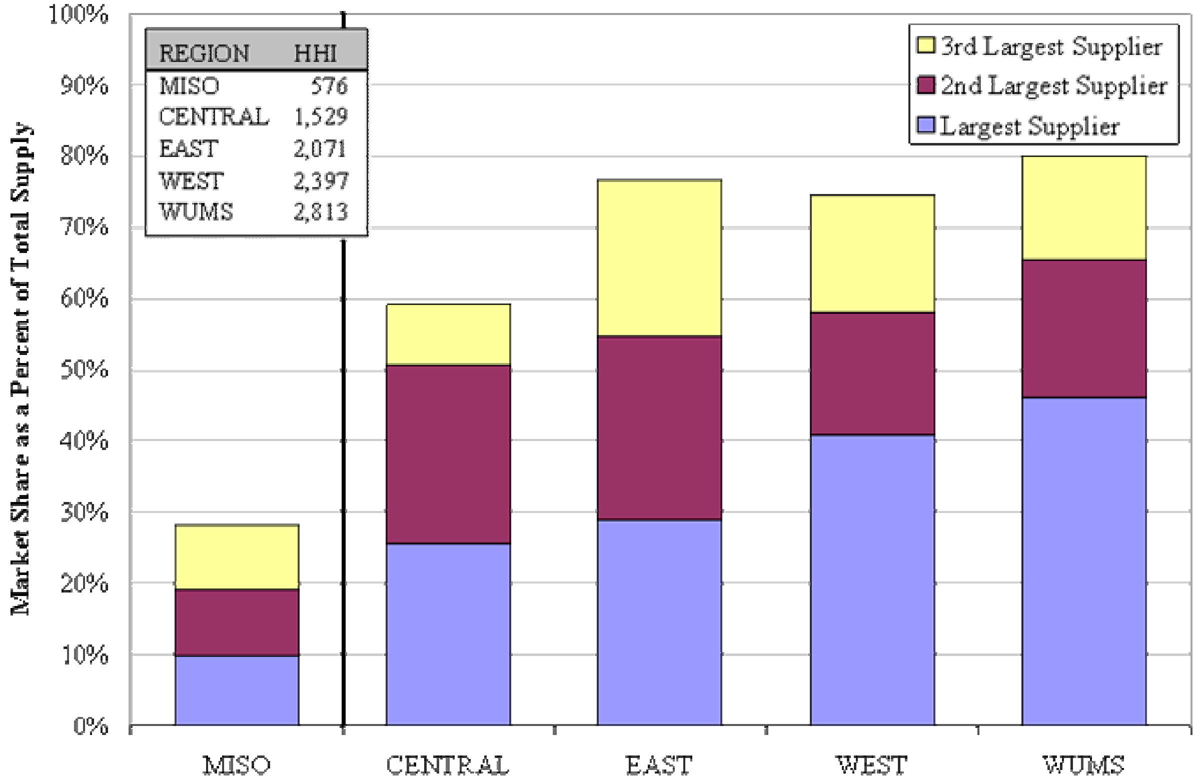
This first subsection provides three structural analyses of the market. The first is an overview of the concentration of both the market as a whole and the various sub-regions within the market. The remaining analyses address the frequency with which suppliers in the Midwest ISO region are "pivotal", i.e., needed to serve load reliability or resolve transmission constraints. In general, the later 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 of 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 index 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 affect on the competitiveness of the market. Nonetheless, the HHI values for the Midwest ISO as a whole and within each sub-region are shown in Figure 61.

Figure 61: Market Shares and Market Concentration by Region



The market concentration of the entire Midwest ISO region is relatively low at an HHI of 576. The largest three suppliers combined have a total market share of less than 30 percent. These metrics indicate that the market is generally conducive to robust competition. 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 expose 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 62 shows percentage of hours during which one or more suppliers are pivotal, which is to say the fraction of hours with an RDI less than one.

Figure 62: Pivotal Supplier Frequency by Load Levels
2005 and 2006

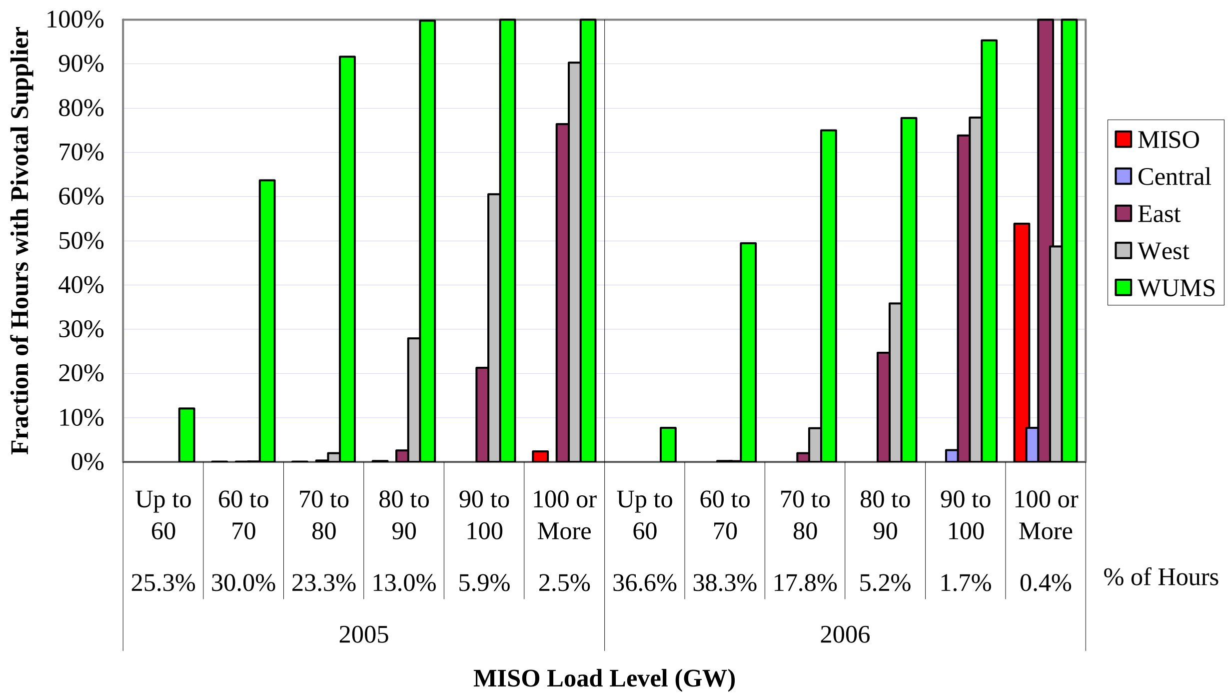
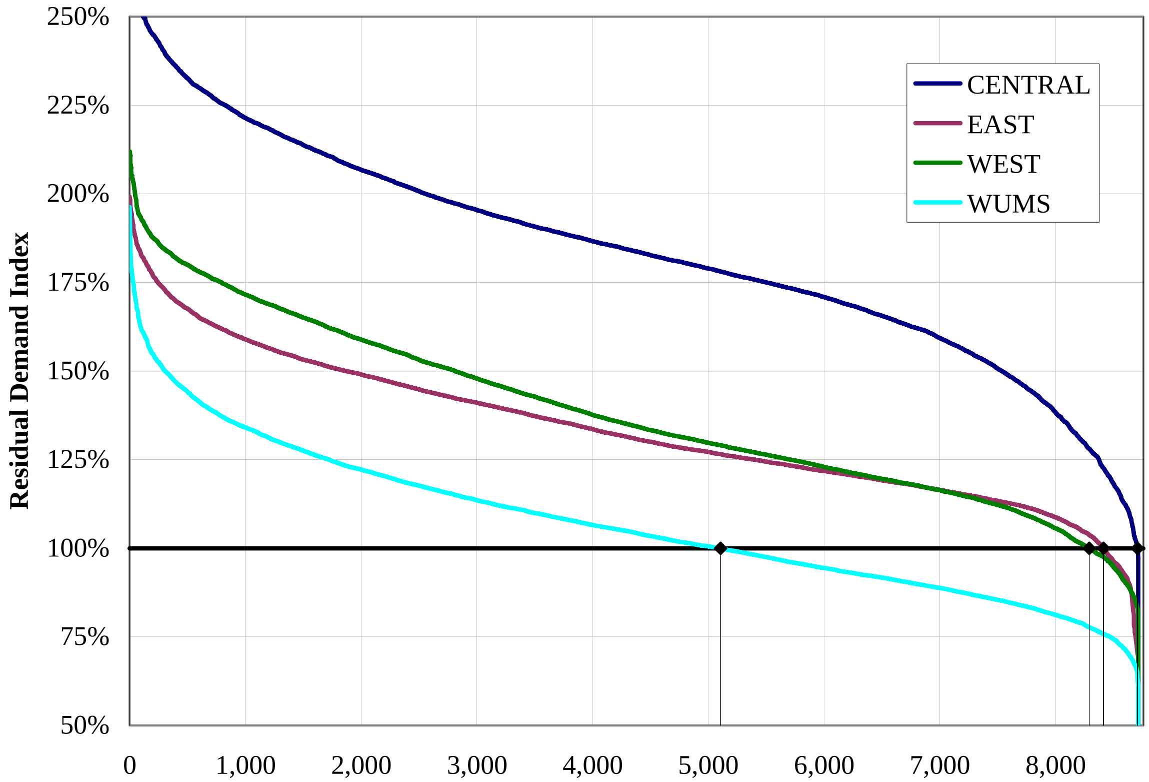


Figure 62 shows that there is limited competition in the WUMS region at all load levels. When load is higher than 60 GW (63 percent of the time), there is a pivotal supplier in WUMS 65 percent of the hours. The West and East regions do not exhibit a pivotal supplier in a substantial share of hours, except when load exceeds 80 GW (7.3 percent of the hours).

To provide additional information regarding how pivotal the largest supplier is in different numbers of hours, Figure 63 shows the residual supplier index in its raw form as an hourly duration curve from its highest (most competitive) to lowest index value (least competitive).

Figure 63: Residual Demand Index Duration Curves
2006: All Hours

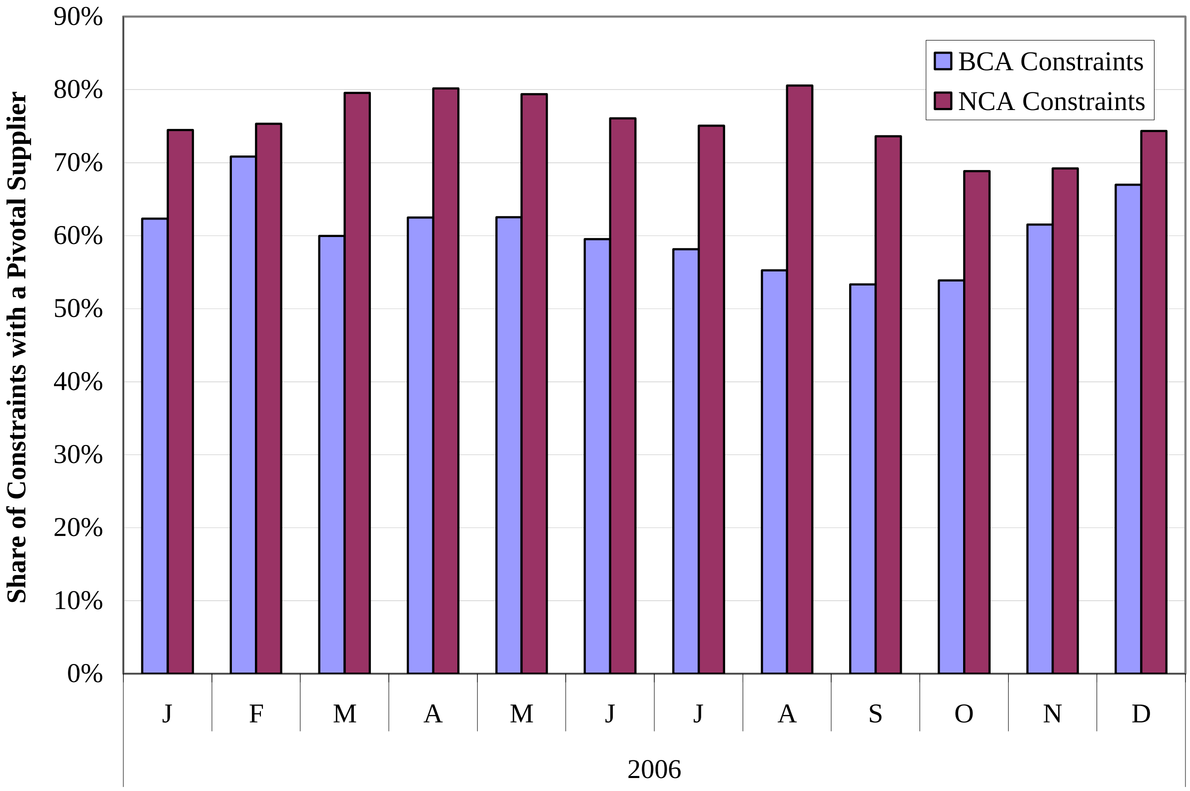


These curves show there were very few hours with a pivotal supplier in the Central region and in the Midwest ISO as a whole. However, the WUMS region has one or more pivotal suppliers in 42 percent of hours. It also shows that under the highest load conditions, more than 40 percent of the load in WUMS could not be served without the resources of the largest supplier. This justifies, in part, the treatment of WUMS as a Narrow Constrained Area ("NCA") under the mitigation measures in the Midwest ISO tariff. The East region had a pivotal supplier in 3 percent of the hours. The West region, where a second NCA was defined during 2006, had a pivotal supplier in only 4 percent of the hours in 2006. The reason that pivotal suppliers were less prevalent in the West than in WUMS according to the RDI metric is because the RDI does not isolate the "into Minnesota" congestion for which the Minnesota NCA was designated. The analysis in the next section identifies pivotal suppliers on individual constraints.

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 constraints. This sub-section provides such an analysis. The analyses in this sub-section detect potential local market power concerns by identifying when a supplier is pivotal relative to a particular transmission constraint. A supplier is pivotal for a constraint when 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 nearest to the constraint. If these resources are all owned by the same supplier, this supplier is likely to be pivotal. Figure 64 shows the portion of the active constraints that have at least one pivotal supplier by month in 2006.

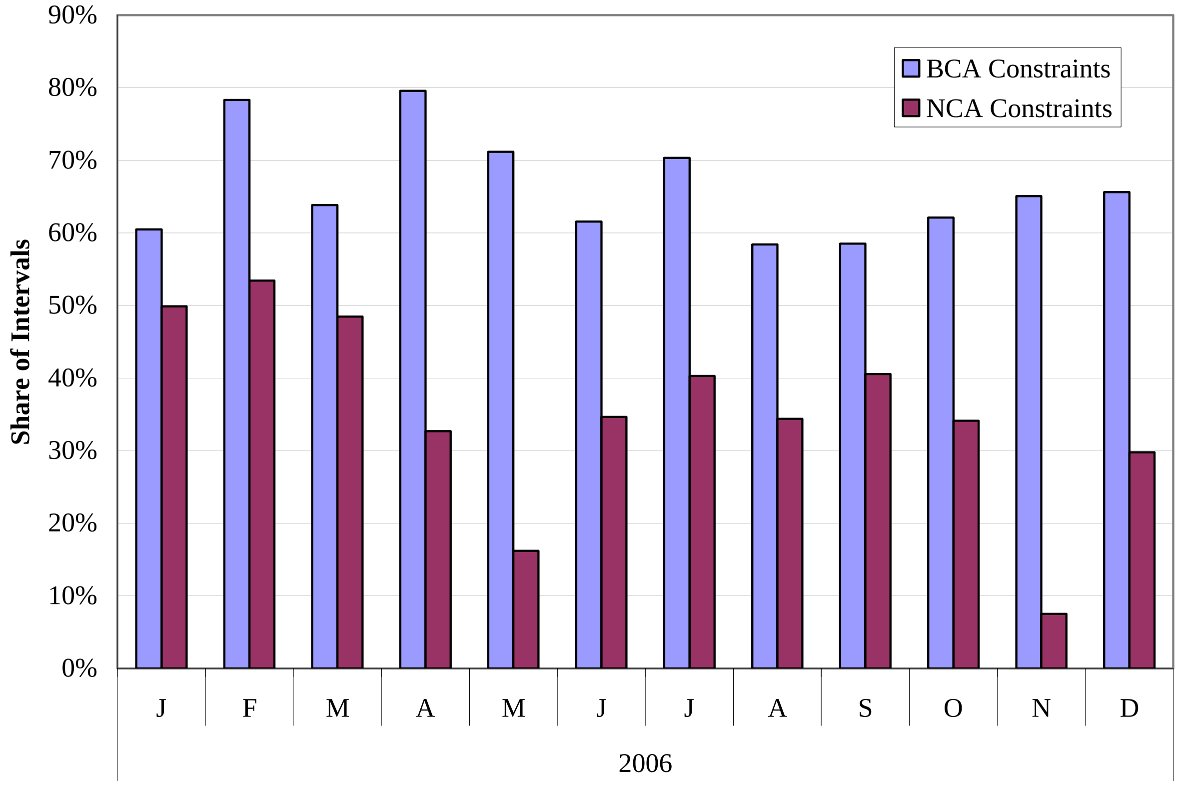
Figure 64: Percent of Active Constraints with a Pivotal Supplier



This analysis reveals that 60 percent of active BCA constraints and 76 percent of active NCA constraints had a pivotal supplier. These results reveal that while local market power is most commonly associated with NCA constraints, a large share of BCA constraints also create substantial local market power.

Figure 65 shows the overall percentage of intervals during 2006 when at least one supplier was pivotal for a BCA or NCA constraint. This analysis differs 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 65: Percent of Intervals with Least One Pivotal Supplier



There was an active BCA constraint with at least one pivotal supplier in 66 percent of the hours during 2006. The regional distribution of BCA constraints varied throughout the year, yet the total frequency remained relatively constant.

While NCA constraints had pivotal suppliers more frequently when binding than BCA constraints, the frequency of binding transmission congestion in WUMS was significantly less than in BCA areas. Hence, the percent of intervals with a pivotal supplier was lower in NCA areas at 35 percent of all hours. The NCA share of intervals exhibits a downward trend that correlates with the decreased congestion into WUMS later in the year.

These results indicate that potentially substantial local market power exists throughout the Midwest ISO area, and stresses 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 2006 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 marginal cost in order to raise market clearing prices or RSG payments. Physical withholding occurs when a unit that would be economical 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. We examine both of these issues in this subsection.

1. Economic Withholding

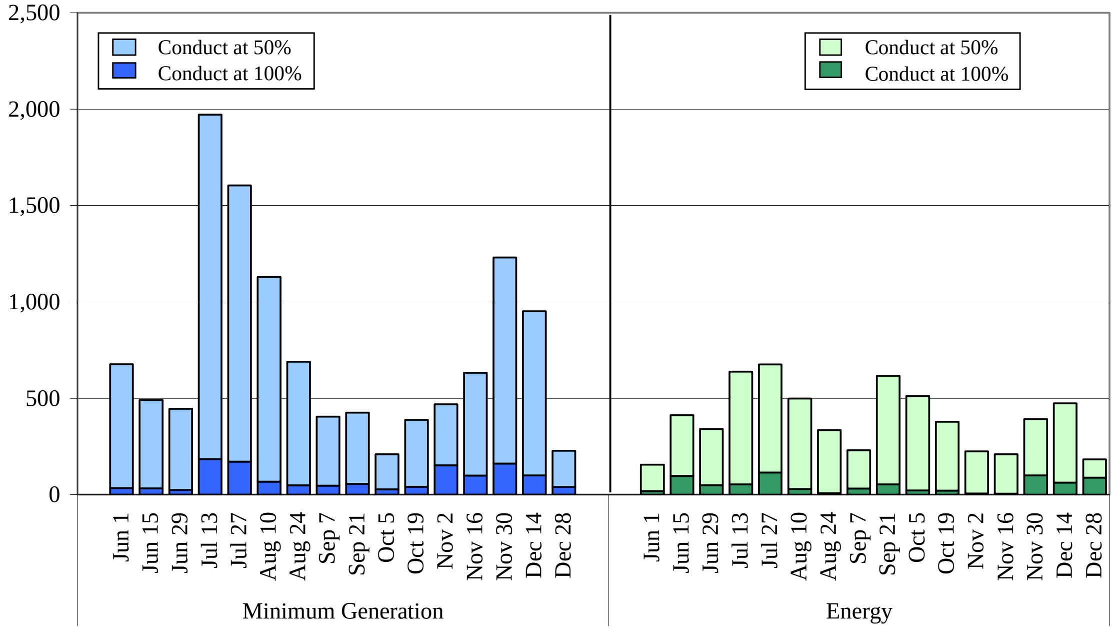
Economic withholding occurs when a supplier raises its offer price substantially above competitive levels to raise the market price. An analysis of economic withholding requires a comparison of actual offers to competitive offers.

Suppliers lacking market power maximize profits by offering resources at marginal costs. 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 inputs, 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."

Figure 66 shows the average amount of generation offered at levels that exceed the conduct thresholds. The figure includes two panels: the left side shows minimum generation offers (i.e., no-load and energy offered up to a resource's EcoMin), the right side panel shows energy offers. In each of the panels, the analysis shows two values: the quantities of supply offered at prices that exceed 50 percent and those that exceed 100 percent of market power mitigation conduct thresholds in the Midwest ISO Tariff (i.e. an offer that is greater than the reference level plus one-half of the threshold would exceed 50 percent of the conduct threshold). The calculations are averages for each two-week period from June to December in the real-time market. We focus primarily on the real-time market because if the outcomes of the real-time market are competitive, they will discipline all forward markets, including the Midwest ISO's day-ahead market.

Figure 66: Conduct at 100 percent and 50 percent of Conduct Threshold
Real-Time Market



The results in Figure 66 indicate that the average quantities exceeding the mitigation thresholds were very low. The quantities of energy offers exceeding 50 percent of the mitigation thresholds were also very low. The potential economic withholding via energy offers is generally the conduct that would affect energy prices.

Figure 66 shows that the quantities of minimum generation exceeding 50 percent of the conduct thresholds peaked at almost 2000 MW. These quantities are still relatively low given that more than 100 GW are typically offered in the Midwest ISO (although lower quantities are online in the real-time market). This conduct generally does not affect energy prices unless it changes commitment patterns. For example, units whose minimum generation offers exceed 50 percent of the conduct threshold are frequently committed anyway, in which case they would not affect energy prices. The mitigation measures limit their potential to increase RSG costs.

Although the analysis above is useful, it can include quantities that do not identify potential economic withholding because the resources themselves may not be economic. For example, when prices in an off-peak hour are $40 per MWh and a peaking resource with a reference level of $120 per MWh submits an energy offer of $250 per MWh, it will be shown in the prior figure as violating the conduct threshold. However, it is not economic at its competitive reference level and, therefore, is not being withheld. Likewise, some resources may be dispatched at their maximums, even though they have increased their offer by more than 50 percent of the conduct threshold, these units would not be deemed to have been withheld.

To address this issue and more accurately 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 – i.e., 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.

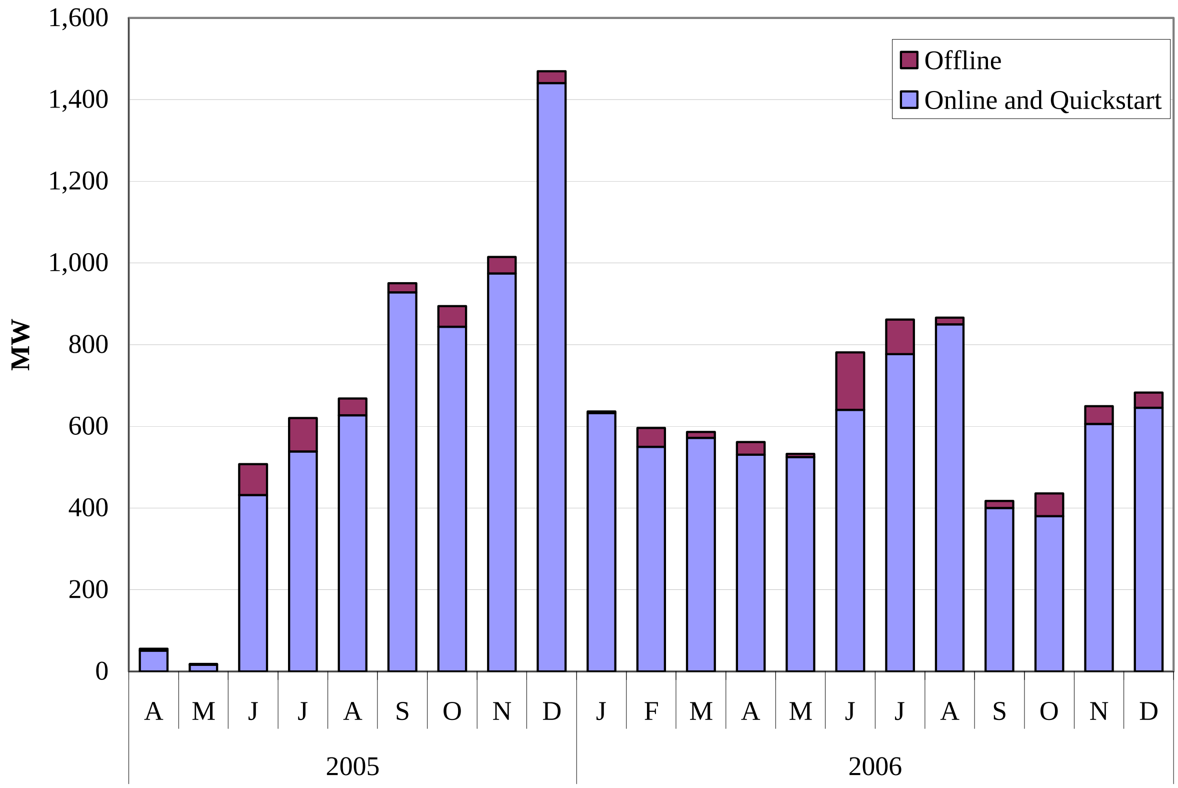
Q_i^{prod} is the actual observed production of the unit. The difference between Q_i^{econ} and Q_i^{prod} represents how much the unit fell short of its economic production level. However, some units are dispatched at levels lower than their three-part offers would indicate due to transmission constraints, 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:

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

Q_i^{offer} = offer output level of i.

By using the greater of actual production or the output level offered at the clearing price, units that are subject to ramp limitations are excluded from the output gap. Figure 66 shows the average amount of generation economically withheld from the real-time energy market using the output gap metric.

Figure 67: Average Hourly Output Gap
Real-Time Market



The results in Figure 67 indicate that the average quantities exceeding the mitigation threshold are very low and have generally correlated with energy prices and load. This is expected because increased energy prices effectively reduce the conduct threshold (a fixed dollar amount) and high load suggests that more resources will be needed to meet load and thus be economic

Because any measure of potential withholding will inevitably include quantities that can be justified for a variety of reasons, we generally evaluate not only the absolute level of the output gap, but also how it varies with factors that can create the ability and incentive for a pivotal supplier to exercise market power. This allows us to test whether a participant's conduct is consistent with an attempt 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 in the case of a pivotal supplier) 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 68 through Figure 71 show the results of our output gap analysis for each of the Midwest ISO sub-regions.

Figure 68: Real-Time Market Output Gap
Central Region

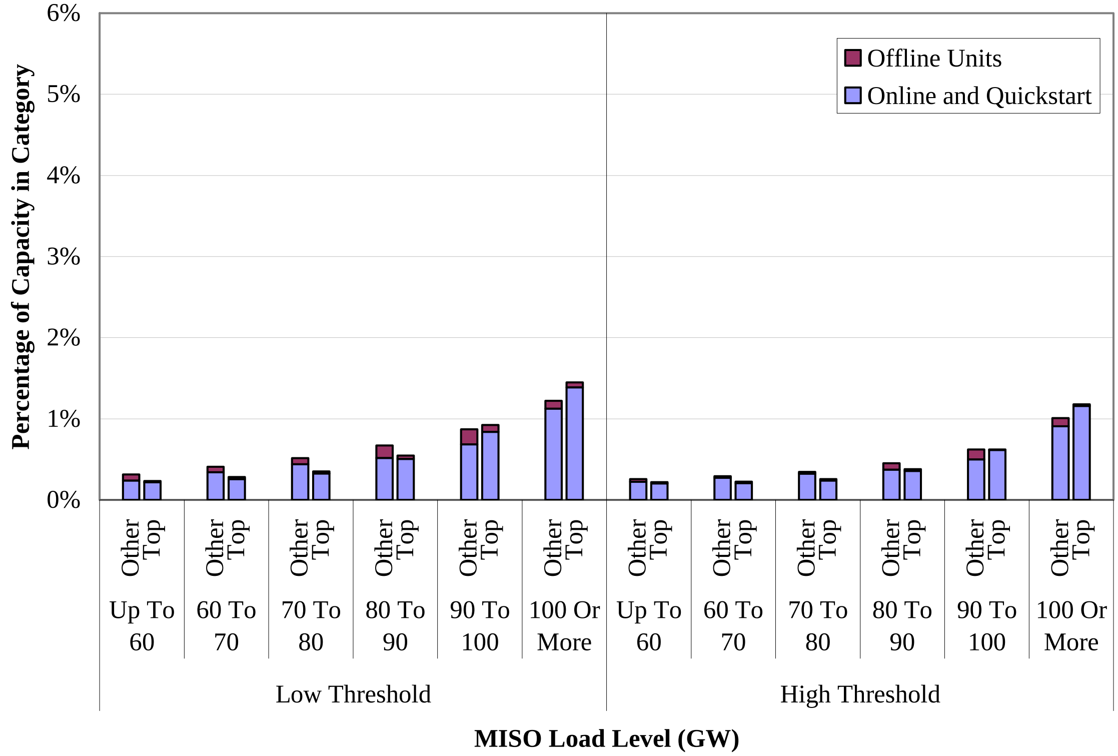


Figure 69: Real-Time Market Output Gap
East Region

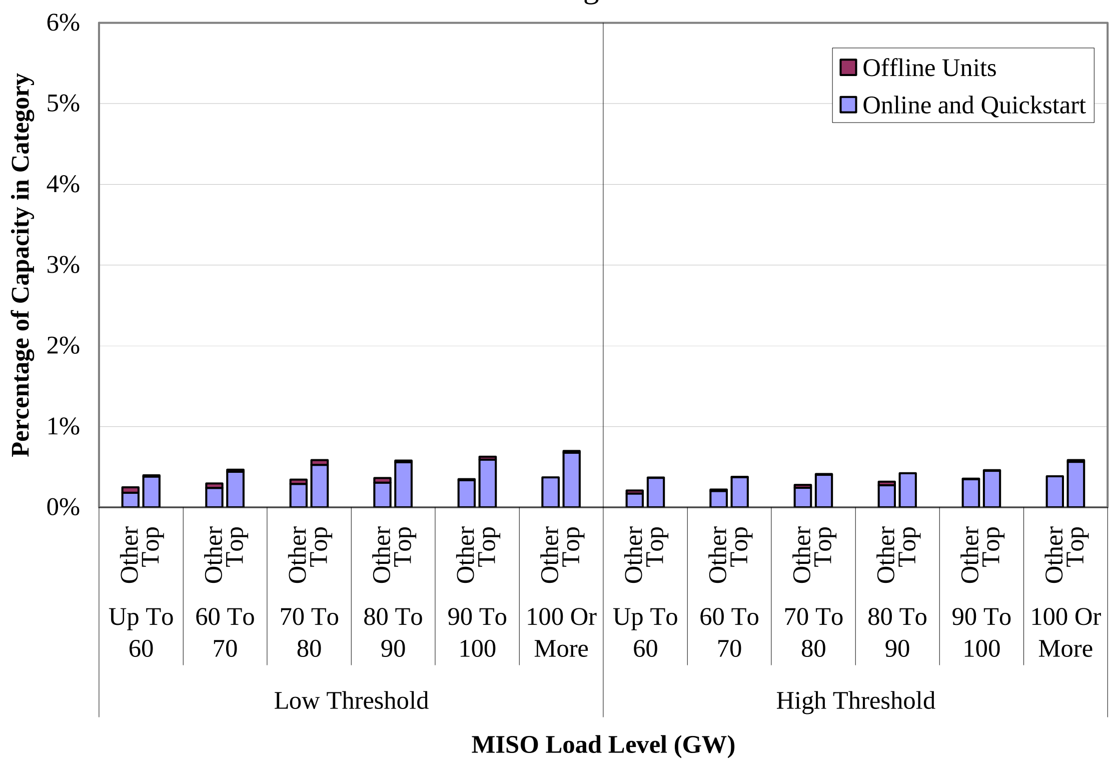


Figure 70: Real-Time Market Output Gap
West Region

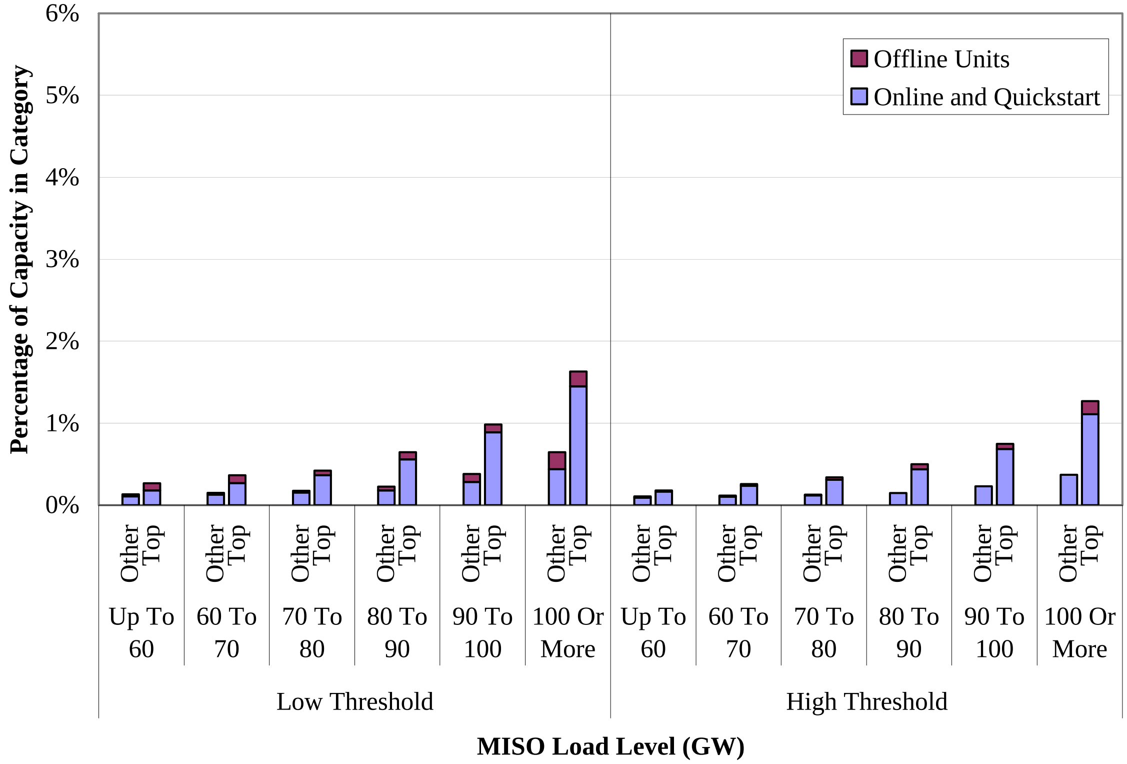
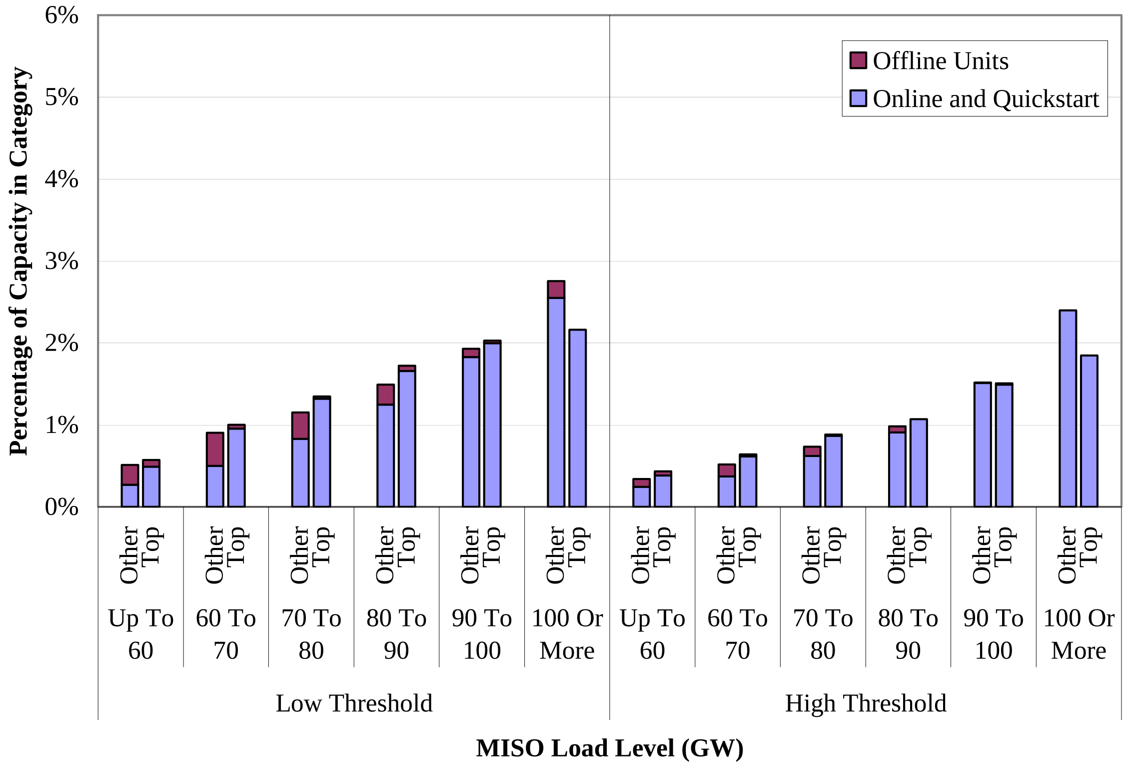


Figure 71: Real-Time Market Output Gap
WUMS



These figures reveal a number of important observations. First, 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. The output gap results are higher in WUMS in part because the thresholds applied to resources in WUMS are lower than the BCA thresholds ($36/$18 versus $100/$50). Second, the output gap levels at the lower threshold are also generally very low. This indicates that resources are seldom offered just below the conduct threshold.

Third, 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, the output gap quantities for the largest suppliers in each region are generally slightly higher than those for other suppliers, but the difference is not large enough to generate a substantial competitive concern. Overall, these results suggest that participants are engaged in very little economic withholding and, thus, that the market is performing competitively.

2. Physical Withholding

This sub-section of the report examines forced outages and other unplanned deratings to assess whether participants manipulated the availability of resources in a manner consistent with physical withholding. Although we provide these overall analyses in the context of 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 7 days), longer-term forced outages, and deratings. Like the output gap analysis above, these quantities of each measure 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 72**Error! Reference source not found.** through Figure 75 display these results for each of the Midwest ISO's four regions.

Figure 72: Real-Time Deratings and Forced Outages
Central Region

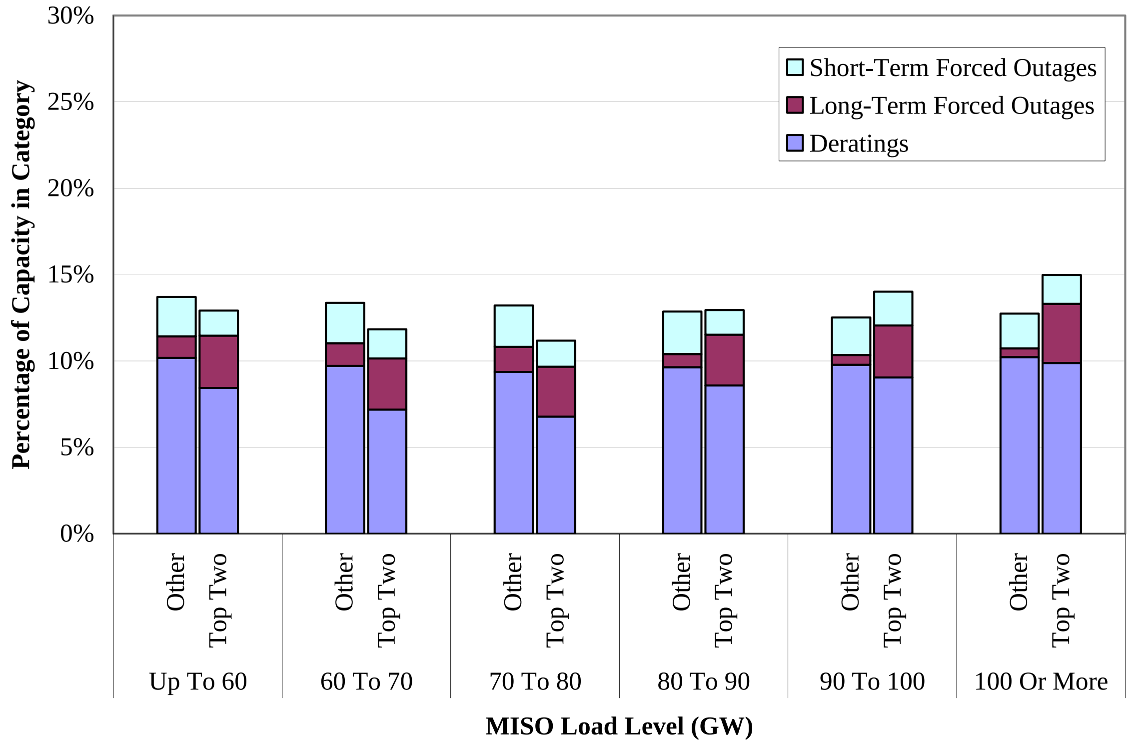


Figure 73: Real-Time Deratings and Forced Outages
East Region

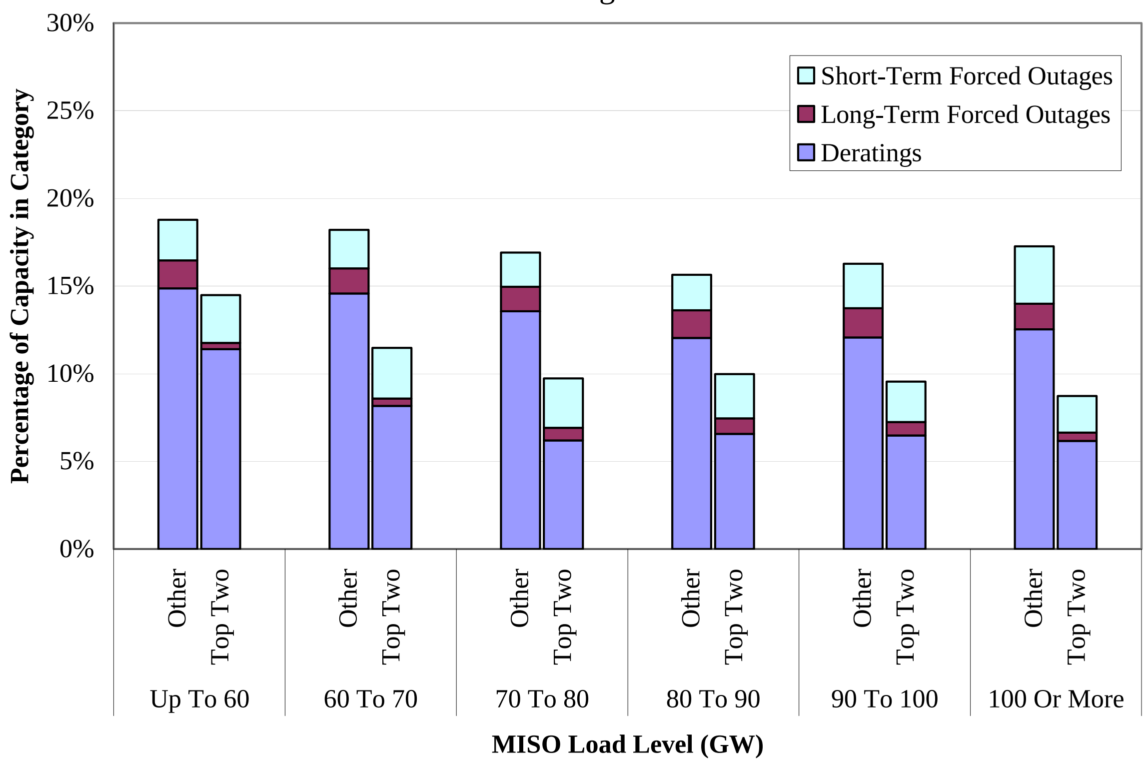


Figure 74: Real-Time Deratings and Forced Outages
West Region

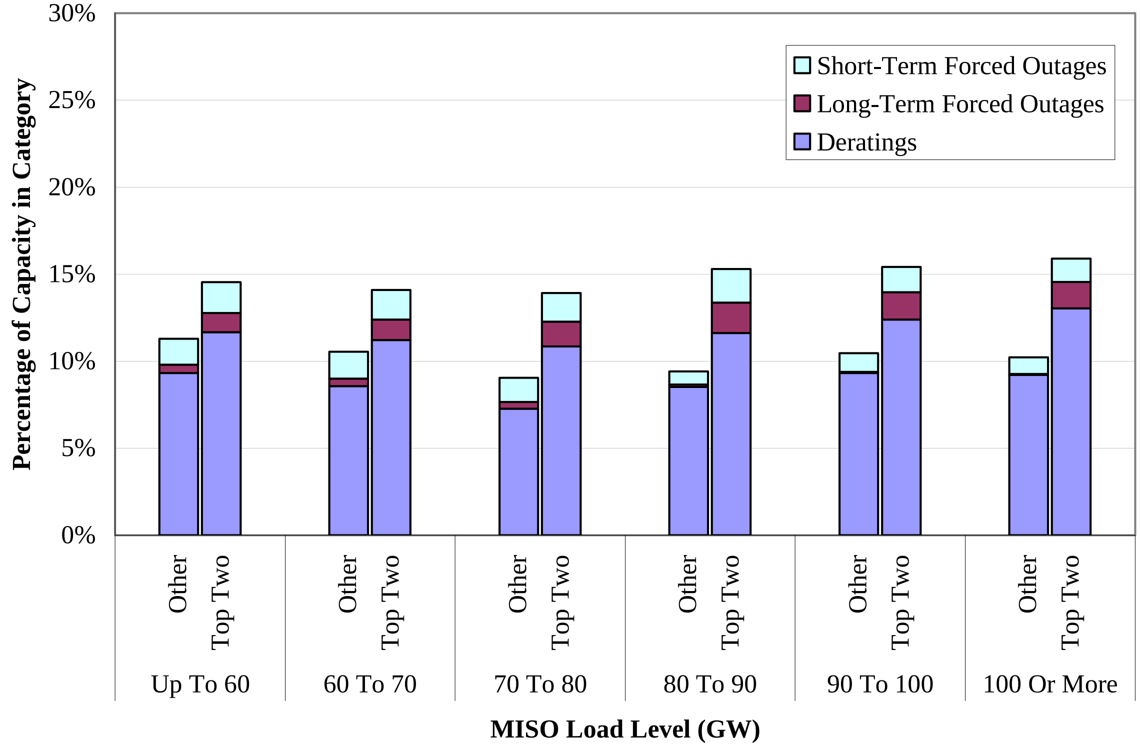
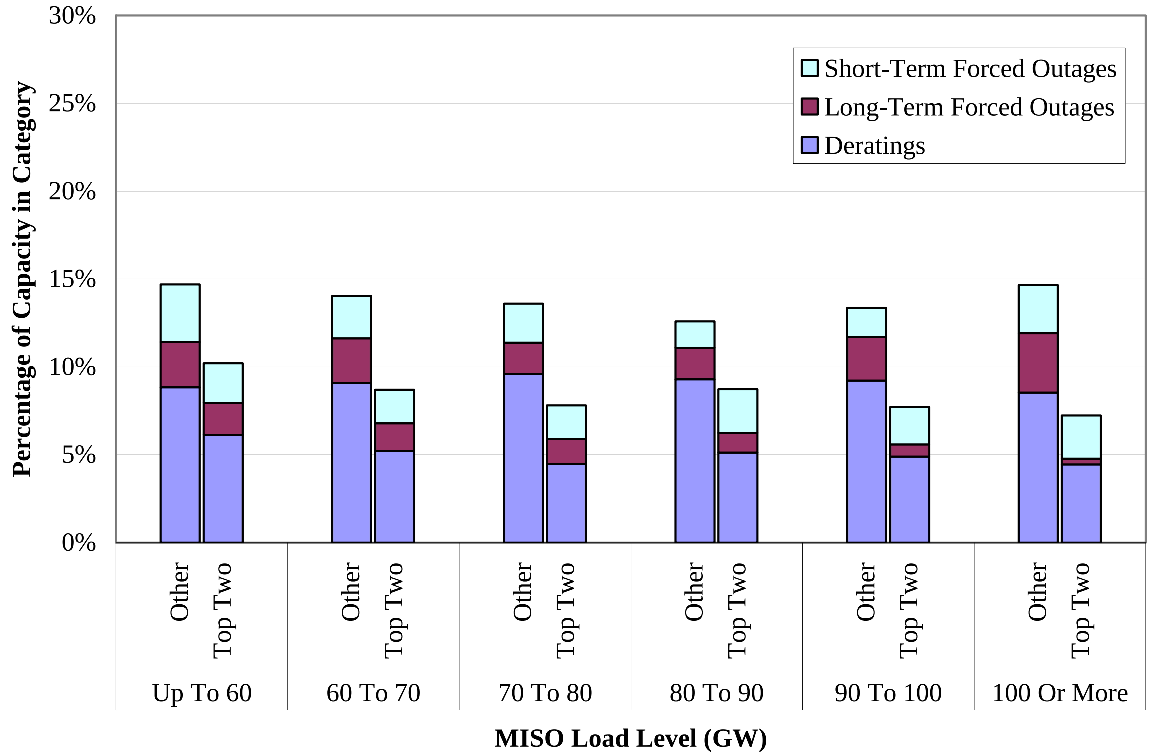


Figure 75: Real-Time Deratings and Forced Outages
WUMS



As discussed above, the results 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 do not rise significantly under peak load conditions. The quantities for the largest suppliers are generally lower than for other suppliers (those that are less likely to have market power), with the exception of the results in the West region. In the West region, where the total outages and deratings of the largest suppliers are relatively high, the short-term forced outages are particularly low during the peak load hours.

Overall, these results are nearly identical to those from 2005 and do not indicate that substantial physical withholding occurred in 2006. Nonetheless, as part of our market monitoring function, we investigate individual outages and deratings that create substantial congestion or other price effects. These investigations confirmed the results shown above that physical withholding was not a significant problem in 2006.

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 mitigate 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 mitigation process is nearly completely automated.

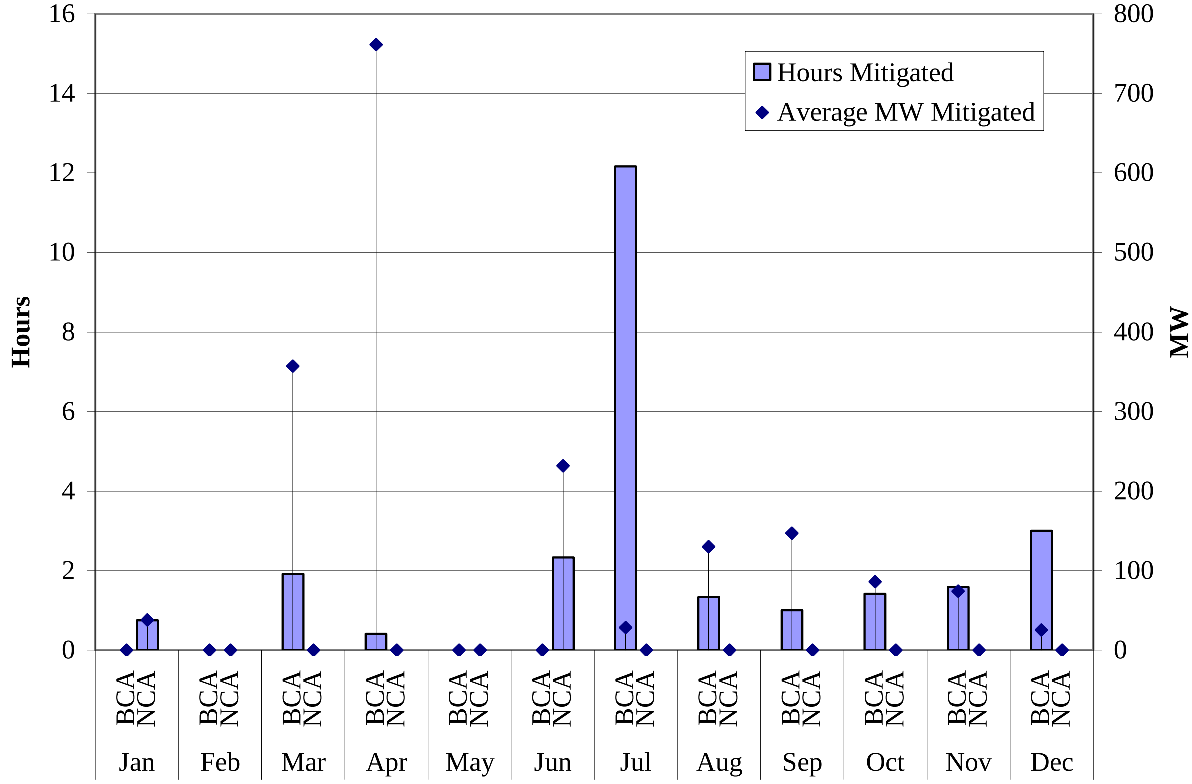
Market Participants are potentially subject to mitigation only when transmission constraints are binding that can create substantial locational market power. When a transmission constraint is binding, one or more suppliers may be in the position to exercise market power due to the lack of competitive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

BCAs and NCAs are based on the electrical properties of the transmission network in order to identify when and where market power is likely to arise. 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 cannot be designated in advance. Therefore, BCA constraints are defined dynamically as constraints 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. 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 regarding 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 76 shows the frequency and quantity of mitigation in the real-time market by month.

Figure 76 indicates that NCA mitigation occurred less frequently than BCA. However, both classes of mitigation were relatively infrequent. There were 14 BCA events and 3 NCA mitigation events. The most mitigation occurred in July, when mitigation was imposed in 12 hours. This result is somewhat surprising given the fact that FERC suspended BCA mitigation between May 10 and July 20, 2006. Although mitigation was infrequent during 2006, local market power remains a significant issue in the Midwest ISO region as evidenced by the pivotal supplier analyses earlier in this section. In general, mitigation was infrequent because participants did not engage in significant economic or physical withholding, even in the presence of local market power.

Figure 76: Real-Time Mitigation by Month



The prior analysis focuses on mitigation of economic withholding in the real-time energy market. Participants can also exercise market power by raising their offers when they do not face competition to resolve a constraint or satisfy a local reliability requirement. This can compel the ISO to make substantially higher RSG payments. The mitigation measures address this conduct after three prerequisites have been satisfied.

First, the unit must be committed for a constraint or a local reliability issue. Second, the unit's offer must exceed the conduct threshold. Finally, the impact portion of the test requires that the mitigated RSG payment is less than one-third the unmitigated payment. Figure 77 shows the frequency and amount by which RSG payments were mitigated in each month of 2006.

Figure 77: Real-Time RSG Mitigation by Month

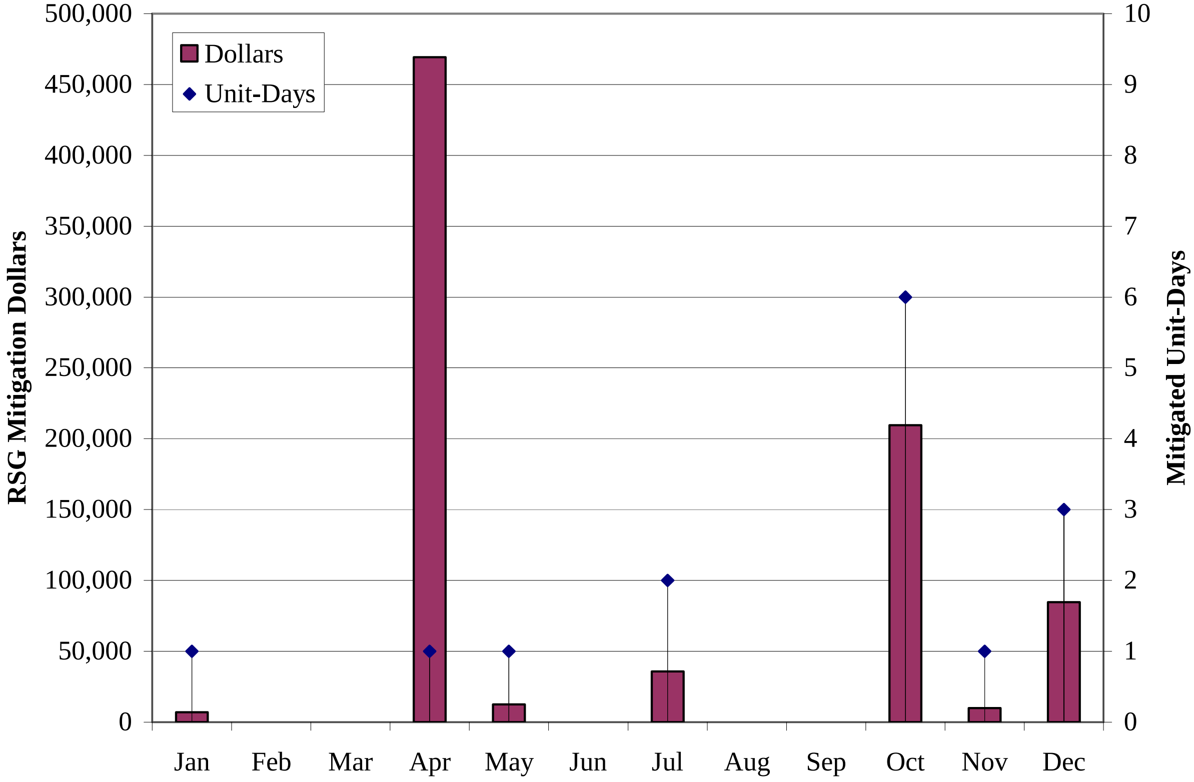


Figure 77 shows that only modest amounts of the total RSG payments were mitigated in most months. The modest levels of mitigation were due to the fact that suppliers with local market power generally did not attempt to exercise market power. For the year, less than $1 million of RSG payments were mitigated. This is a marked decrease from 2005. There are several contributors to the RSG mitigation decrease, including substantially reduced RSG levels overall (65 percent average monthly decline) and increasingly competitive offer patterns.

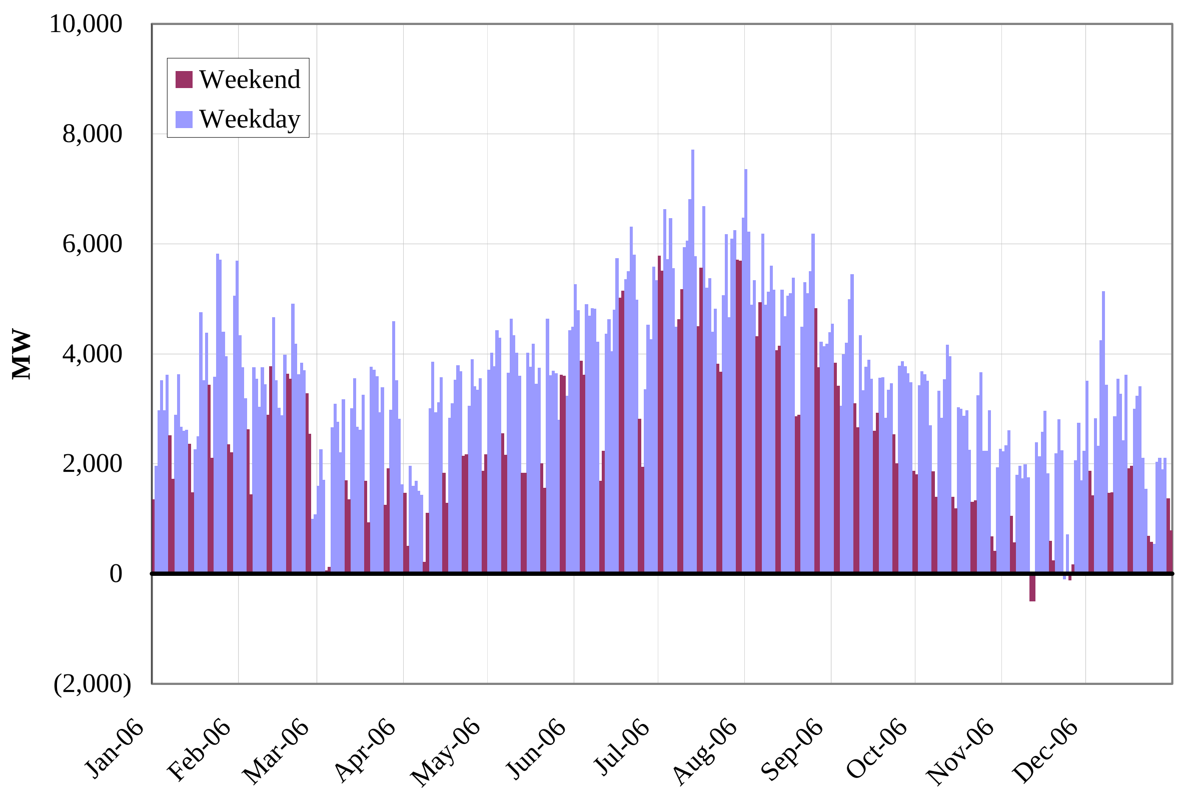
VII. External Transactions

The Midwest ISO relies heavily on imports to serve its load and meet its operating reserve requirements. 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 processes used to schedule the transactions.

A. Import and Export Quantities

We begin this section with an overview of external transactions. Figure 78 shows the average hourly net imports scheduled in the day-ahead market.

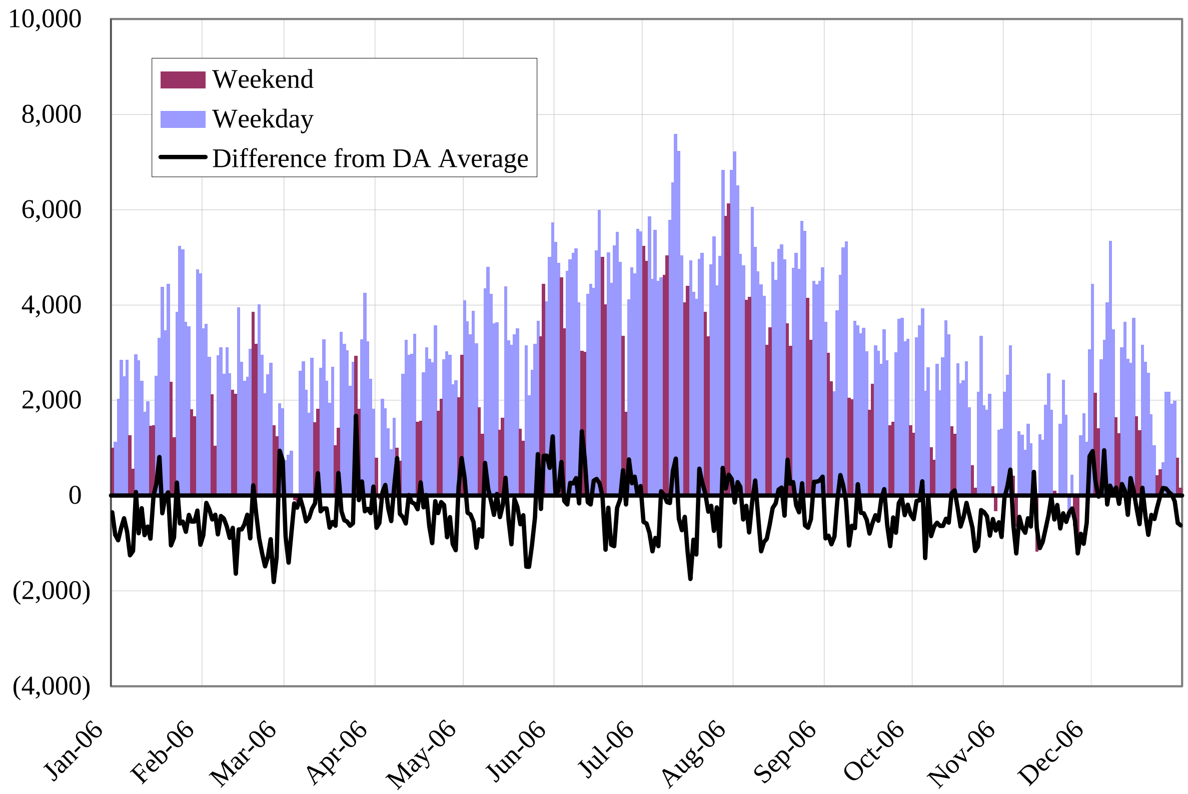
Figure 78: Average Hourly Day-Ahead Imports
All Hours



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, the pattern of net imports during 2006 was seasonal, with the largest imports occurring during the summer under peak load conditions. Net imports also rose sharply in late November, largely due to planned transmission and generation outages that led to high prices in Minnesota.

Net imports in the real-time market can vary substantially from the levels scheduled in the day-ahead market. Figure 79 shows the average hourly net imports scheduled in the real-time market each day over all interfaces.

Figure 79: Average Hourly Real-Time Imports
All Hours



This figure shows that the net imports in the real-time market were comparable to the net imports scheduled in the day-ahead market. On average, the Midwest ISO imports almost 4.2 GW in on-peak hours and close to 2 GW in off-peak hours. More than one-third of these net imports come over the Manitoba Hydro interface. However, there was a consistent bias toward over scheduling day-ahead imports relative to real-time imports. Real-time imports average 3.0 GW, a 10 percent decline on average from imports scheduled in the day-ahead market. The majority of this 300 MW real-time difference is due to lower real-time import scheduling into WUMS

(220 MW) and the West region (130 MW). The East region averages slightly higher real-time imports than day-ahead imports. Similar to the effect of underbidding load in the day-ahead or high scheduling of virtual supply, reductions in net imports from day-ahead to real-time increase the need for the Midwest ISO to commit additional generation and rely more on peaking resources to meet real-time load.

To better show where the Midwest imports and exports originate, the following analysis shows net imports by interface. The interface between the Midwest ISO and PJM, who both operate LMP markets over relatively wide geographic areas, is one of the most significant interfaces. Figure 80 shows the average net imports scheduled for the Midwest ISO-PJM interface in each hour of the day.

Figure 80: Hourly Average Real-Time Imports from PJM
April through December 2005

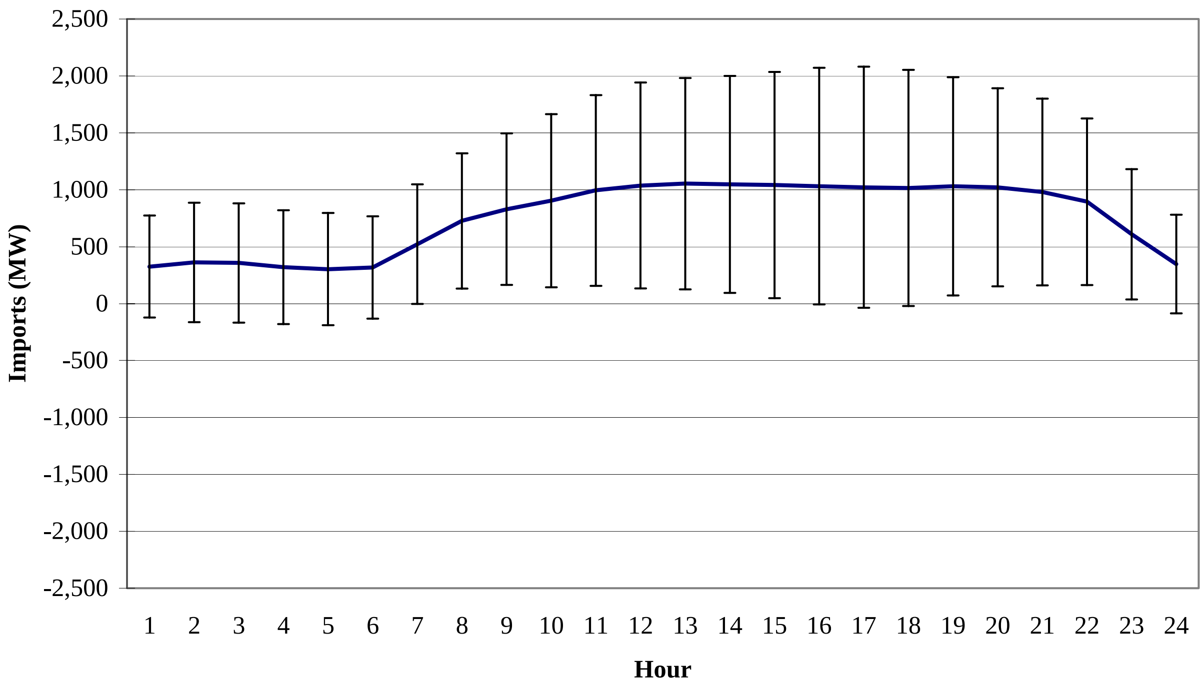


Figure 80 shows that the Midwest ISO generally imports more power from PJM during the peak hours of the day than in the off-peak hours, and is a net importer overall. However, the standard deviation of the net imports is large, particularly in the peak hours. As the figure indicates, the magnitude and direction of the flows between the two markets is highly variable. This characteristic of the external transactions with PJM is due to the fact that the supply resources in the two areas have similar cost characteristics. Therefore, it may be economic to import in some hours and export in others. The relative prices in PJM and the Midwest ISO should govern the real-time net interchange of power between the two areas.

Figure 81 shows the net imports across the Canadian interfaces. The Midwest ISO exchanges power with Canada through interfaces with the Manitoba Hydro Electricity Board ("MHEB") and 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.

Figure 81: Hourly Average Real-Time Imports from Canada
April through December 2005

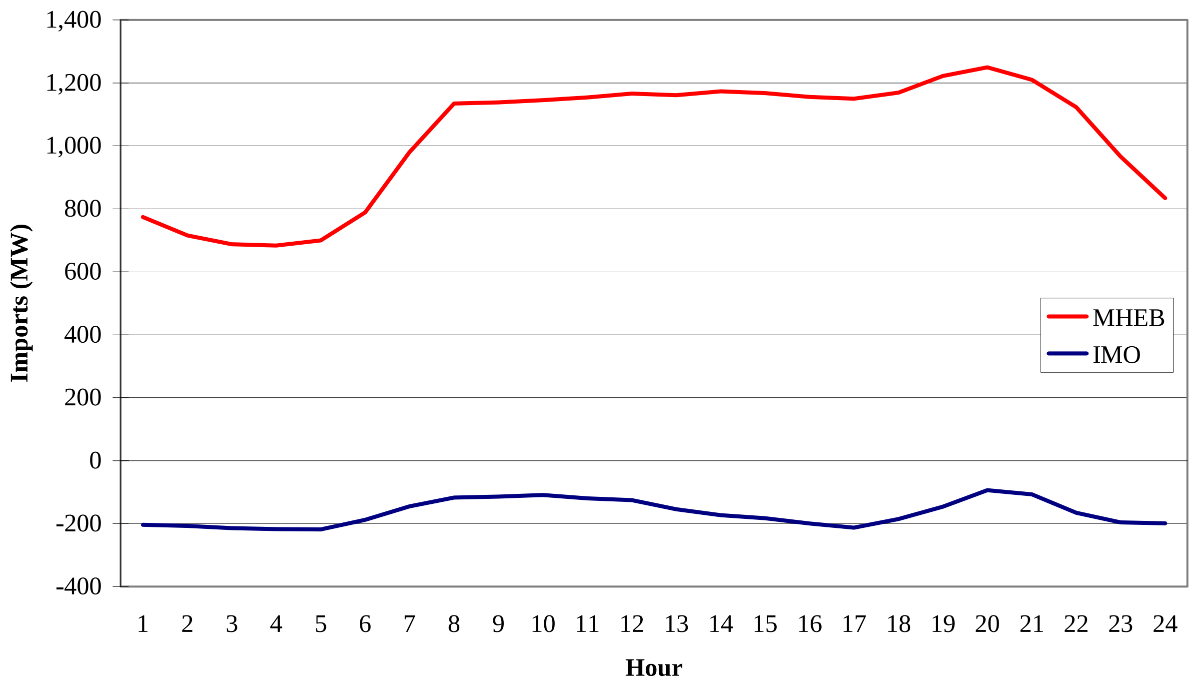
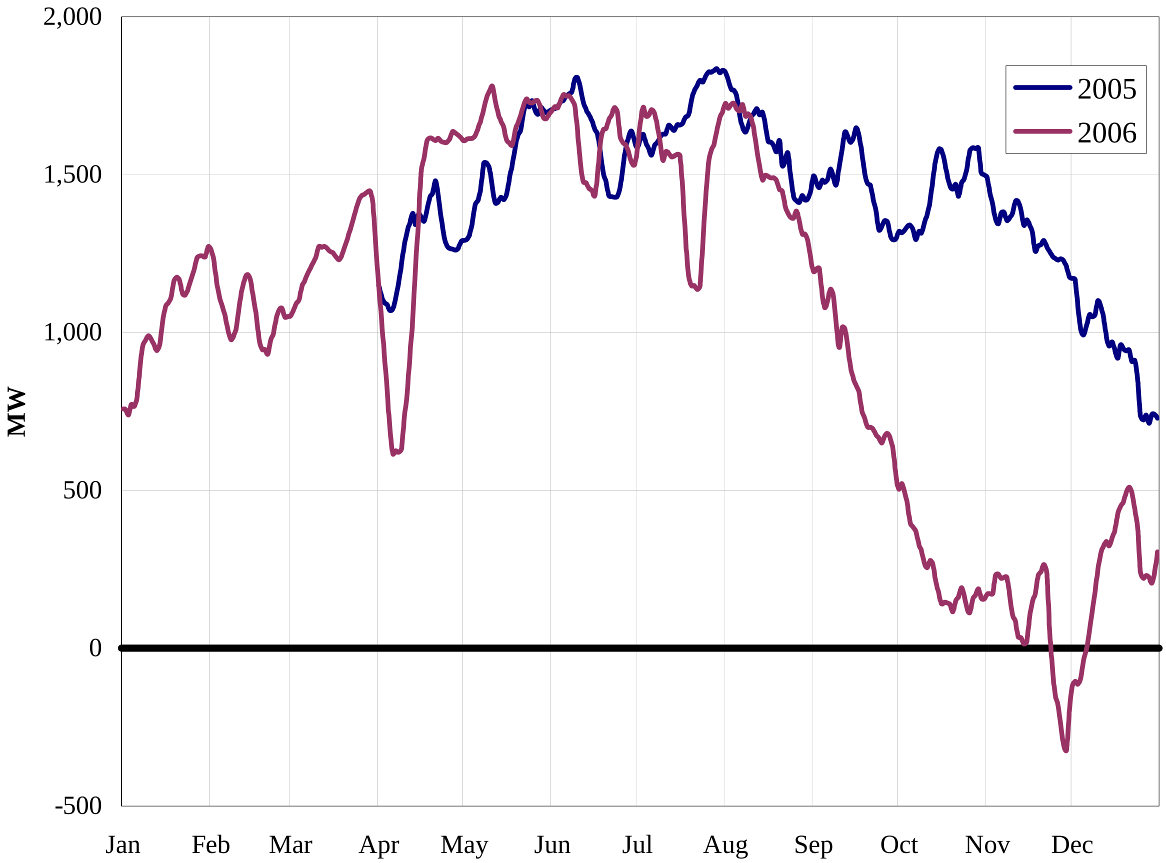


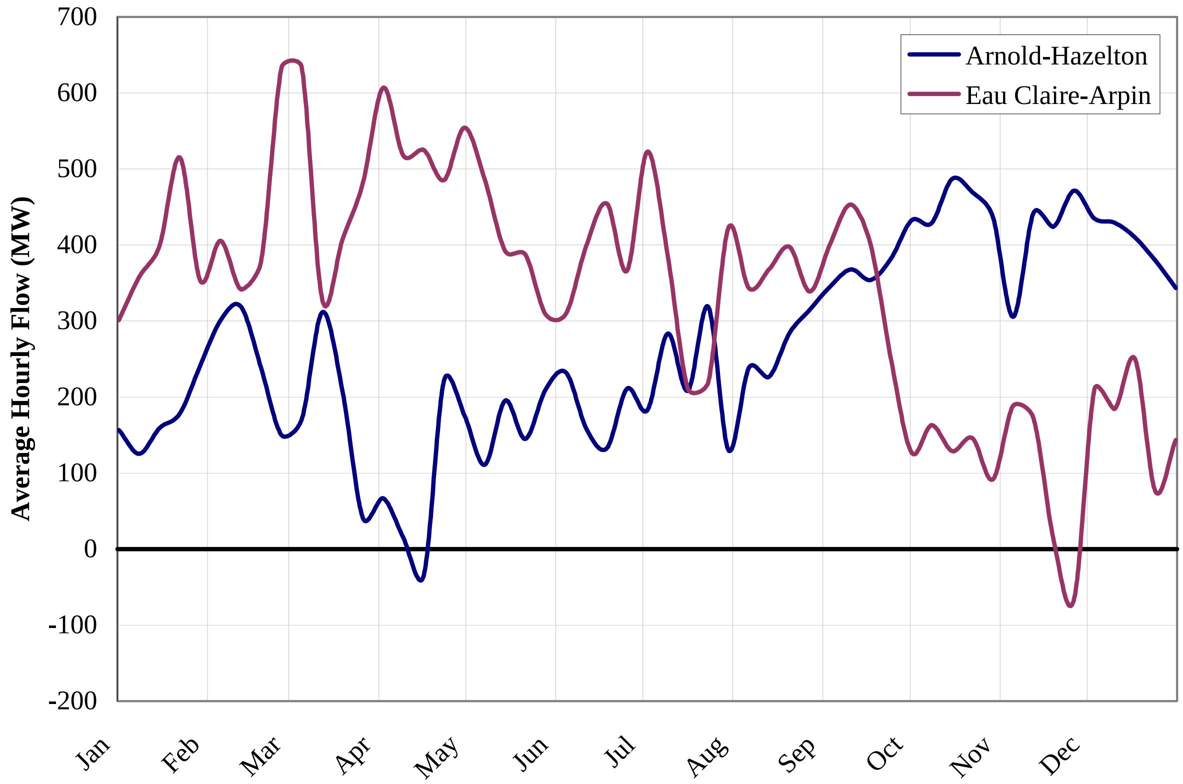
Figure 80 shows that exports to Ontario were generally higher in off-peak hours and mid-afternoon, and lower during morning ramp up and evening ramp down periods. Net imports from MHEB were generally higher in the peak hours and lower in the off-peak hours. While the hourly pattern remains similar to the pattern exhibited during 2005, imports over the Manitoba Hydro interface decreased substantially during the last four months of 2006 due primarily to poor water conditions affecting the hydroelectric resources in Canada. Figure 80 illustrates the divergence of import levels during September through December 2006 over the Manitoba interface.

Figure 82: Moving Average of Net Imports over the Manitoba Hydro Interface



From October through November 2006, average imports over the Manitoba Hydro interface decreased by nearly 1,500 MW from 2005 levels. During many hours, the flows on the Forbes-Dorsey line (one of the key transmission facilities interconnecting the Midwest ISO and MHEB) were reversed as power was exported to Manitoba. The reduction in imports over the Manitoba Hydro interface has substantially affected the congestion patterns in the West region and WUMS. The reduction in imports increases the flow over power from the south into Minnesota, which has caused constraints in Iowa (most notably, Arnold-Hazelton). It also has tended to reduce exports from Minnesota into WUMS over the Eau Claire-Arpin line. The data plotted in Figure 83 shows the average hourly flow on two key MISO flowgates.

Figure 83: Hourly Flows on Frequently Active Flowgates



The Eau Claire-Arpin line is the main 345 kV line connecting the West Region to WUMS. This interface accounted for [XX] percent of total congestion costs during the first 16 months of market operations. Imports over the Manitoba Hydro interface have a 15 percent shift factor on this constraint, which means that a reduction of 100 MW in imports would result in a 15 MW decline in flow on the constraint. During the first eight months of 2006, the average flow over this line exceeded 400 MW. Over the last quarter of 2006, average flow dropped to 170 MW and congestion was reduced by [XX] percent. This change is almost entirely attributable to reduced flow from Manitoba over the constraint.

Arnold-Hazelton is a key transmission facility in Iowa running north into Minnesota. Before the reduction in imports, the imports over the Manitoba Hydro interface created an average of about 180 MW of counter-flow on this line. The reduction of this counter-flow led Arnold-Hazelton flows to increase substantially and caused frequent transmission congestion in the West region.

B. Convergence of Prices between the Midwest ISO and Adjacent Markets

The prior analyses summarized the import and export quantities at the Midwest ISO's primary interfaces. Our next analysis evaluates the price convergence and net imports between the Midwest ISO and adjacent markets. Our analysis is presented in a series of figures, each with two panels. The left panel is scatter plot of the real-time price differences and the net imports in unconstrained hours. The right panel shows the average hourly price differences and the average absolute value of the hourly price differences on a monthly basis. In an efficient market, prices at the interface should tend to converge when the interface between the regions is not congested.

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. The results for the PJM interface are shown in Figure 84 and Figure 85.

Figure 84: Real-Time Prices and Interface Schedules
PJM and the Midwest ISO

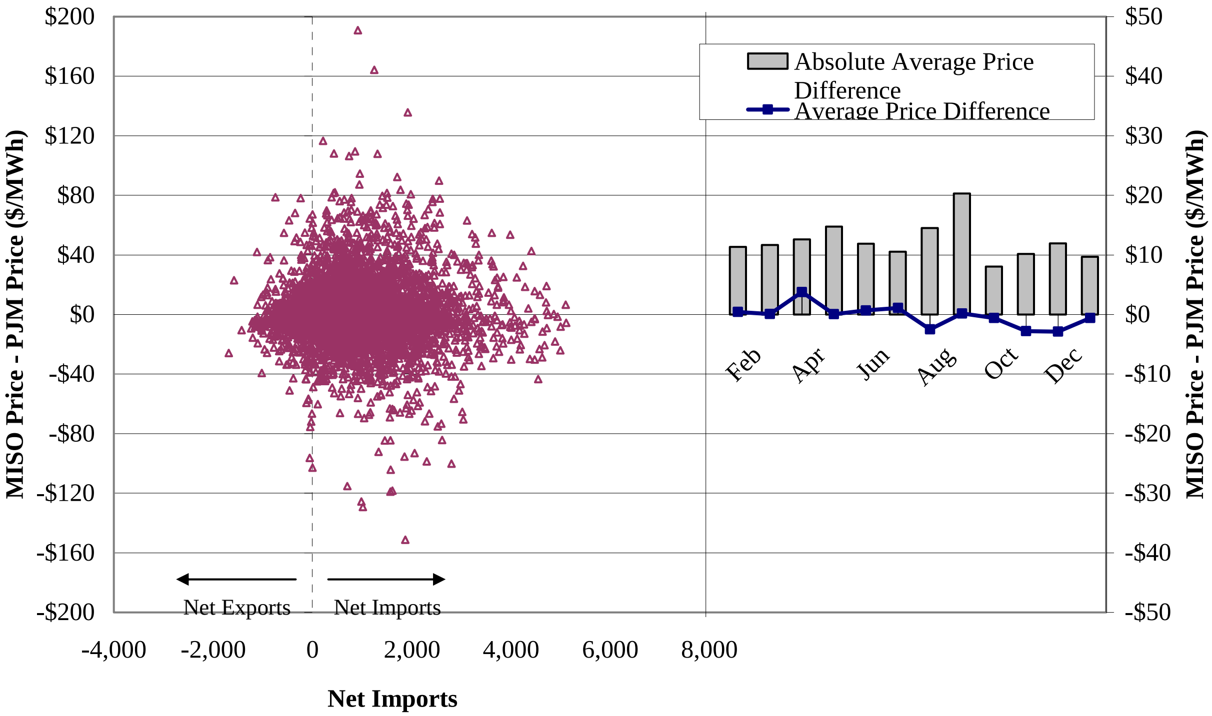
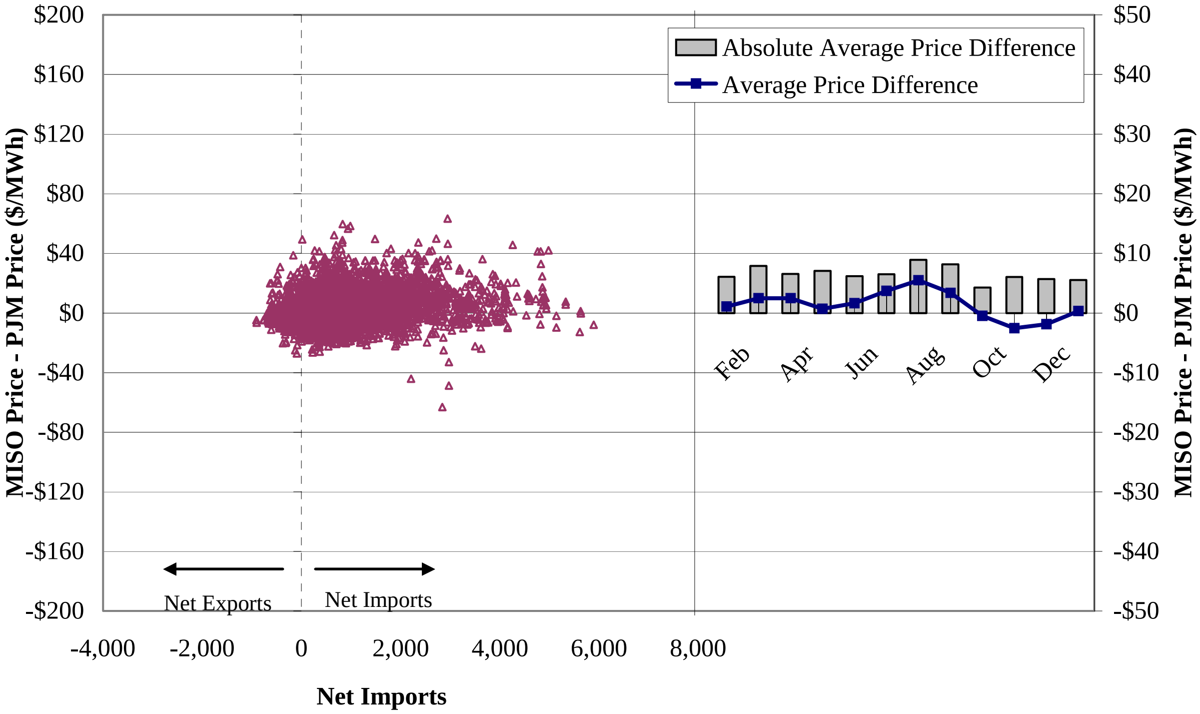


Figure 85: Day-Ahead Prices and Interface Schedules
PJM and the Midwest ISO



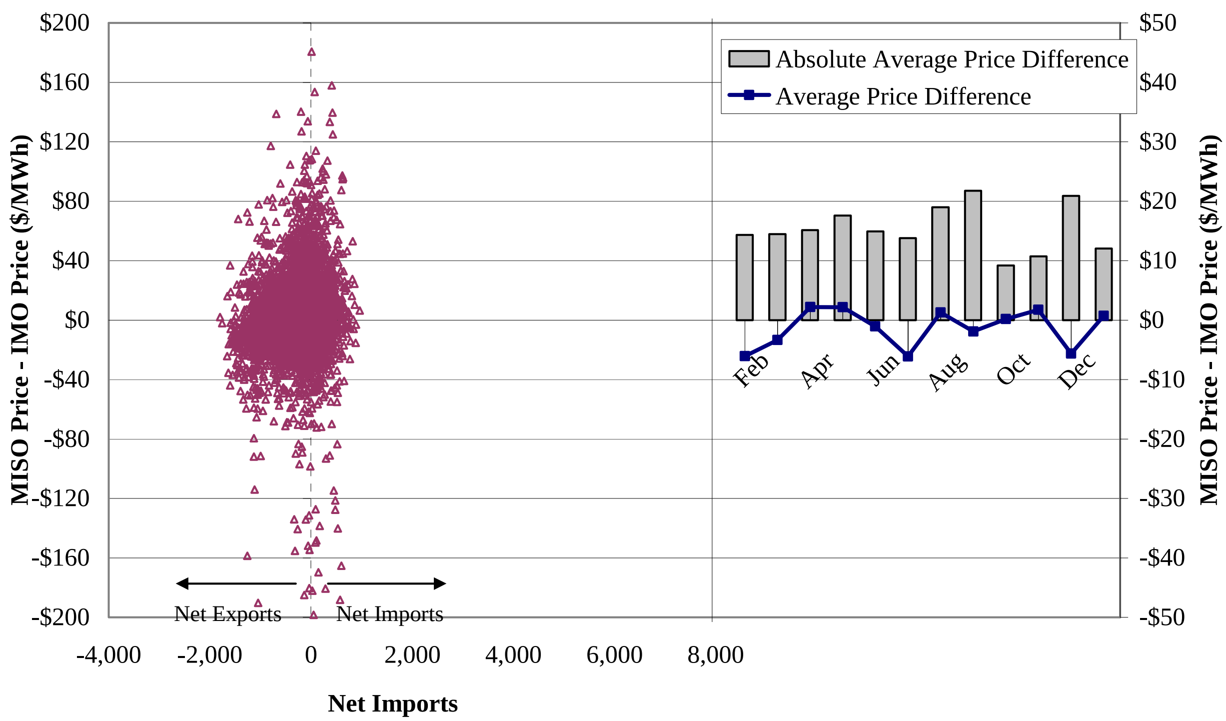
These figures indicate that the prices in the two areas are relatively well arbitraged in most hours. However, there are many hours when substantial price differences prevail. In a number of these hours, the power is flowing from the high-priced market to the lower-priced market (the upper left and lower right quadrants on the left sides of the figures). These instances of counter-intuitive flows can only be explained by the difficulties participants face in arbitraging inter-regional price differences using physical schedules that must be submitted in advance. The convergence is better in the day-ahead market because the prices are much less volatile than in real time.

The figures also show that the Midwest ISO interface prices are slightly higher than PJM's on a consistent basis. This may be due in part to differences in how the interface price is calculated – the Midwest ISO uses an average of all PJM nodes, which can overstate the price under some conditions. Participants have not been fully effective at arbitraging the prices between the two areas.

To achieve better price convergence, we recommend that the RTOs consider expanding the JOA with PJM to optimize the net interchange between the two areas. Under this approach, the participants' interchange transactions would be purely 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 each five minutes 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 86 provides the same analysis for the Midwest ISO – IESO interface.

Figure 86: Real-Time Prices and Interface Schedules
Ontario IESO and the Midwest ISO



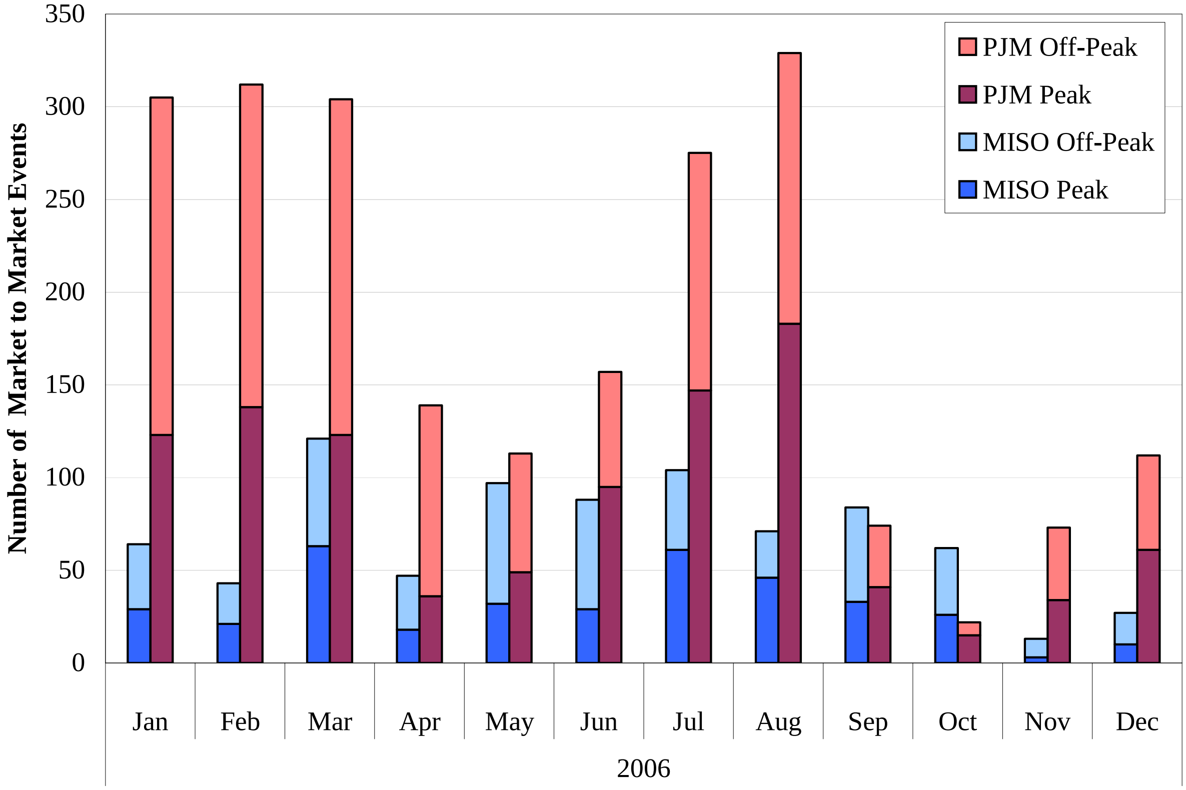
The Midwest ISO is a net exporter of power to Ontario in most hours. On average, the prices in the Midwest ISO are lower than the prices in Ontario, which makes the net exports rational. However, there are many instances when the exports occur and the IMO prices are lower than the prices in the Midwest ISO. The schedules over this interface do not appear to be highly responsive to the price difference between the two markets. Interpreting these results is complicated by the fact that Ontario does not have a nodal market, so the Ontario price may not fully reflect the true value of power being 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. 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). When a market-to-market constraint is activated, the markets exchange shadow prices and the relief requested (the desired reduction in flow) from other market. The shadow price measures the cost of relieving the constraint as determined by each respective market. Each market is entitled to a certain flow on each of the market-to-market constraints. Settlements are made between the ISOs depending on the flows over the constraint caused by the ISOs relative to their entitlements. The market-to-market process is a key to ensuring that generation is efficiently redispatched to manage these constraints and that the prices in these two markets are consistent.

Figure 87 shows the total number of market-to-market events (instances when a market-to-market constraint is binding) by month. One event can last for multiple hours. We identify separate events by assuming the prior even has ended if the shadow price exchanged by the RTOs has been zero or null for 30 minutes. The events in the figure are subdivided by those occurring on constraints located on the Midwest ISO system versus those occurring on the PJM system.

Figure 87: Market-to-Market Events

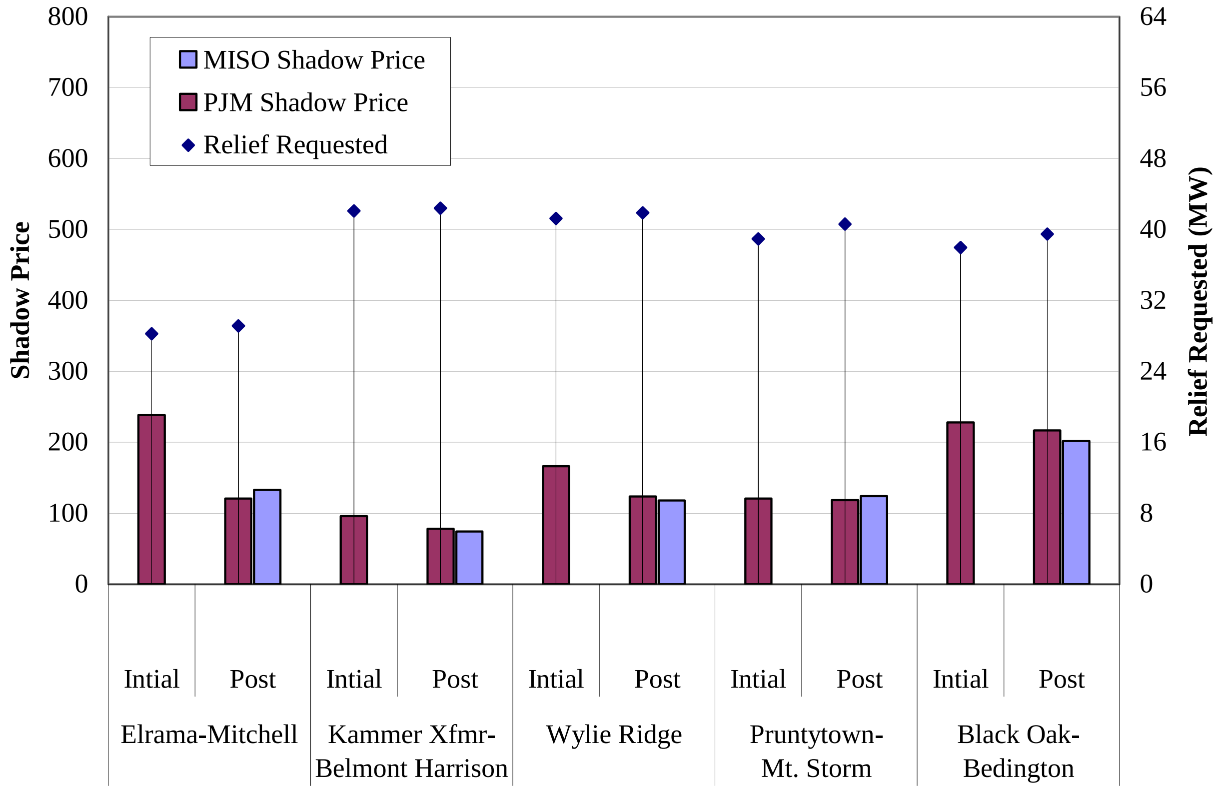


The figure shows that the market-to-market process has been used extensively to coordinate the relief of congestion on each system. With the exception of March 2006, the Midwest ISO market-to-market constraints have tended to correlate positively with monthly load patterns (peaking in the summer) and are evenly divided between the peak and off-peak hours. Market-to-market constraints on PJM flowgates are also evenly divided between peak and off-peak events; however, the frequency of market-to-market events on PJM flowgates was much higher and more variable. The higher frequency is due, in part, to the fact that the Midwest ISO generally has a larger effect on PJM's system than PJM does on the Midwest ISO.

To evaluate how well the market-to-market process has been working, the next two analyses are intended to evaluate convergence of shadow prices on coordinate flowgates between the two RTOs. The metrics used in these figures are average shadow prices and the amount of relief requested during market-to-market events. The initial shadow price is the average shadow prices of the monitoring RTO (the RTO whose system the constraint is on) logged prior to the first response from the reciprocating RTO. To evaluate effect of the coordination, the average shadow price of each RTO is included for the post-initialization period, which should reflect the effects of the coordination.[9]

Figure 88 shows the most frequently called market-to-market constraints on the PJM system. This figure shows the average shadow prices for each RTO and the relief that was requested on average. For purposes of this figure, market-to-market constraints that are binding for at least six intervals (30 minutes) are analyzed to exclude very brief events.

Figure 88: PJM Market-to-Market Constraints
Relief Requested and Shadow Prices



The figure shows that shadow prices generally decline and convergence relatively well over the duration of the event, but good convergence is not always achieved for two reasons. First, the Midwest ISO frequently cannot provide the requested relief at a cost lower than the PJM shadow price. In these cases, a relaxation algorithm effectively lowers the amount of relief the Midwest ISO will provide and sets a shadow price. This process often sets a shadow price in the Midwest

9 Market-to-market initialization in which the reciprocating RTO does not respond has been excluded.

ISO that is substantially lower than PJM's even though, theoretically, the PJM shadow price reflects the true value of the constraint.

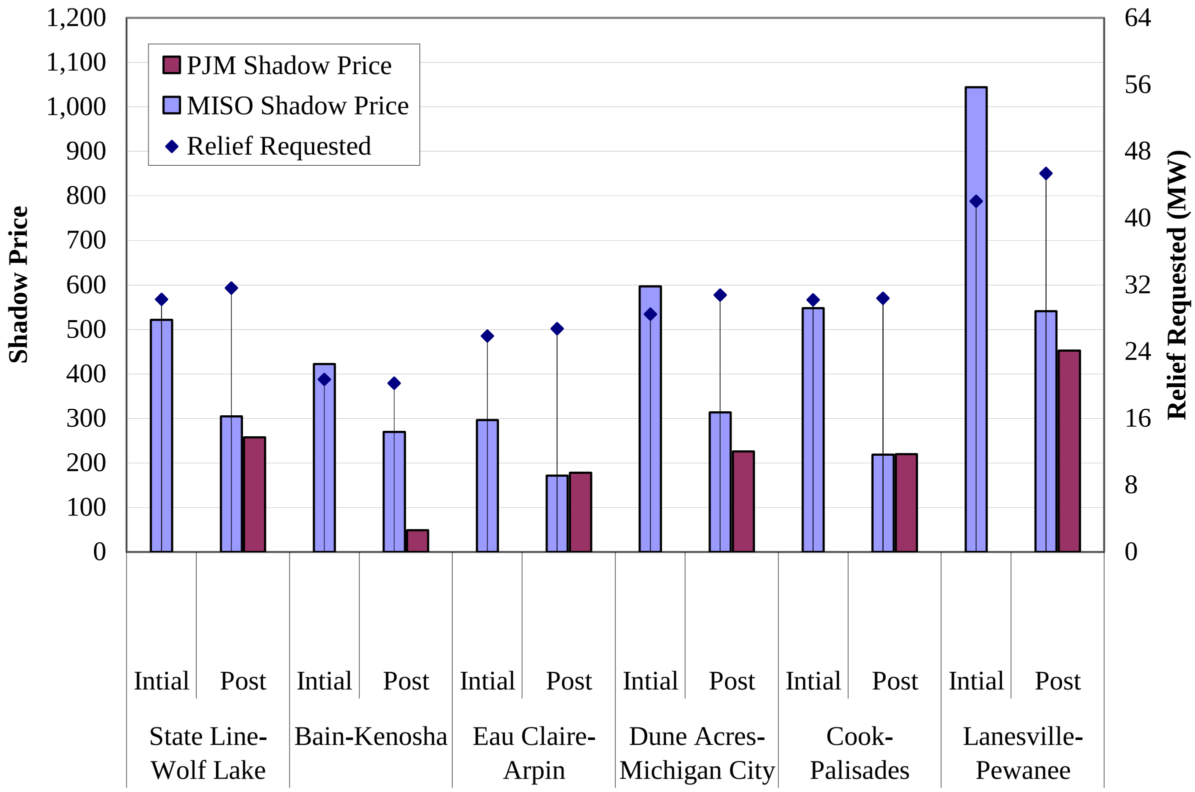
Second, the requested relief is typically not modified over the term of the event. A static quantity of relief requested can cause insufficient relief to be provided from the second RTO even when additional economic relief is available. Static relief quantities can also cause too much relief to be provided, 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.

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.

We have identified a number of cases where the process does not appear to be operating correctly. One case we have detected are instances when the Midwest ISO is responding to a shadow price provided by PJM by redispatching generation, but continuing the redispatch even after the constraint is no longer binding (i.e., there is no congestion in PJM). Either this behavior is due to PJM sending shadow price information that is inconsistent with its LMP calculations or to PJM failing to send a zero shadow price after its internal constraint is resolved.

Our final analysis evaluates the Midwest ISO's market-to-market constraints. This analysis is identical in structure to the prior analysis of the PJM constraints. Figure 89 shows our analysis for the six most frequently called market-to-market constraints on the Midwest ISO system. Eau Claire-Arpin, the most frequently called market-to-market constraint, was called more frequently than all other Midwest ISO market-to-market constraints combined in 2005. As discussed earlier in this section, congestion on this line decreased markedly in 2006, but it remained a frequently called market-to-market constraint.

Figure 89: Midwest ISO Market-to-Market Constraints
Relief Requested and Shadow Prices



Like the results of our analysis of the PJM constraints, this figure shows that the shadow prices decline substantially after the market-to-market constraint is activated and the convergence between the two RTOs is good. However, the initial shadow prices on MISO market-to-market flowgates tend to be higher than the initial shadow prices on the PJM. Figure 89 also shows that, like the PJM constraints, the requested relief is relatively stable over the term of the event. Another common finding of our evaluation of the Midwest ISO market-to-market constraints is that the market-to-market process did not always operate well for these constraints.

To address these issues, we have recommended the RTOs monitor the process more closely, increase its automation, and make other specific changes to the process. For example, we recommend that the RTOs optimize the quantity of relief they request and that they developing a process to coordinate external transactions with non-MISO/PJM areas within the JOA.

D. Intra-Hour Scheduling at PJM Interface

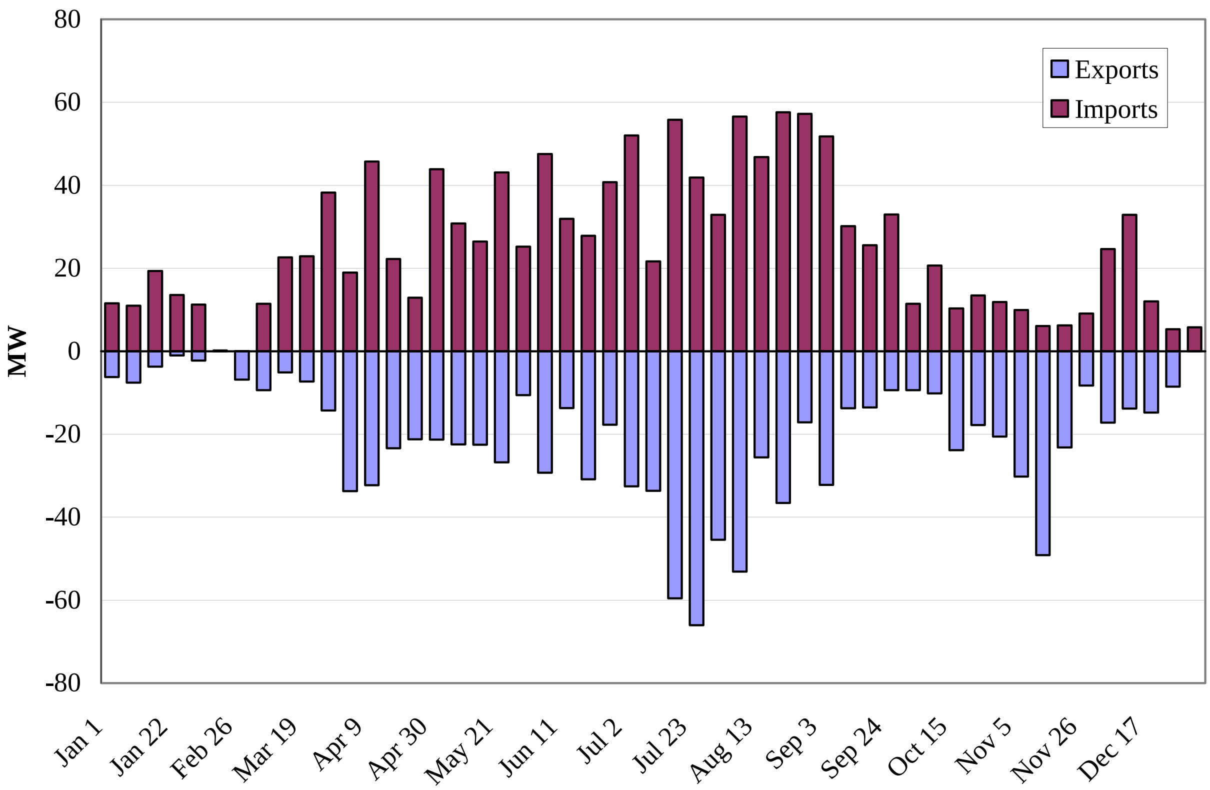
This portion of the report details the extent and impact of intra-hour real-time import and export schedules. These schedules determine the Net Scheduled Interchange ("NSI") between MISO and its neighbors and are a critical element of the MISO market. The majority of the intra-hour schedules are occurring at the PJM interface.

The MISO market rules permit physical scheduling on a time increment as short as 15 minutes. 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 MISO may have to ramp generation up or down substantially to accommodate these schedules.

Intra-hour schedules settle at the average price in the hour in which they occur, even though the transaction may only flow during part of the hour (the transaction is settled as an hourly average – a 400 MW, 15-minute export is treated as a 100 MW hourly export). The divergence between 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 its impact on RSG. A

The following chart shows hourly intra-hour scheduling between MISO and PJM. The chart shows the maximum import and export quantities in any interval in the hour. While shown as hourly values, the imports and exports are not necessarily occurring in the same interval. The largest price effects occur when the intra-hour scheduling utilizes a substantial portion of MISO's capability to ramp generation up or down. During ramp up periods, export schedules of 400 MWs or more can easily use all of the available ramp capability and half or more of the available headroom. When headroom and ramp capability are limited, the prices in MISO will be particularly sensitive to these schedules.

Figure 90: Intra-Hour Scheduling Levels
Weekly Average, 2006



The next two figures show prices at the MISO proxy bus for PJM before and during the intra-hour schedules on a weekly average basis. Figure 91 shows that when the exports are being scheduled on an intra-hour basis the prices are consistently higher by as much as $20/MWh. The price effects have been largest during peak periods, as one would expect. Exports generally have more impact on MISO prices and operations than imports for two reasons. First, prices are more sensitive when generation is being ramped up to accommodate an export than ramped down to accommodate an import. Second, exports may also contribute to MISO commitment of peaking resources as operators commit to meet forecasted load, including net exports. Figure 92 shows that when imports are being scheduled on an intra-hour basis, prices are consistently lower during the schedule than beforehand. This is consistent with MISO reducing generation to accommodate the import.

Figure 91: Intra-Hour Scheduling: Price Impact of Exports
Weekly Average, 2006

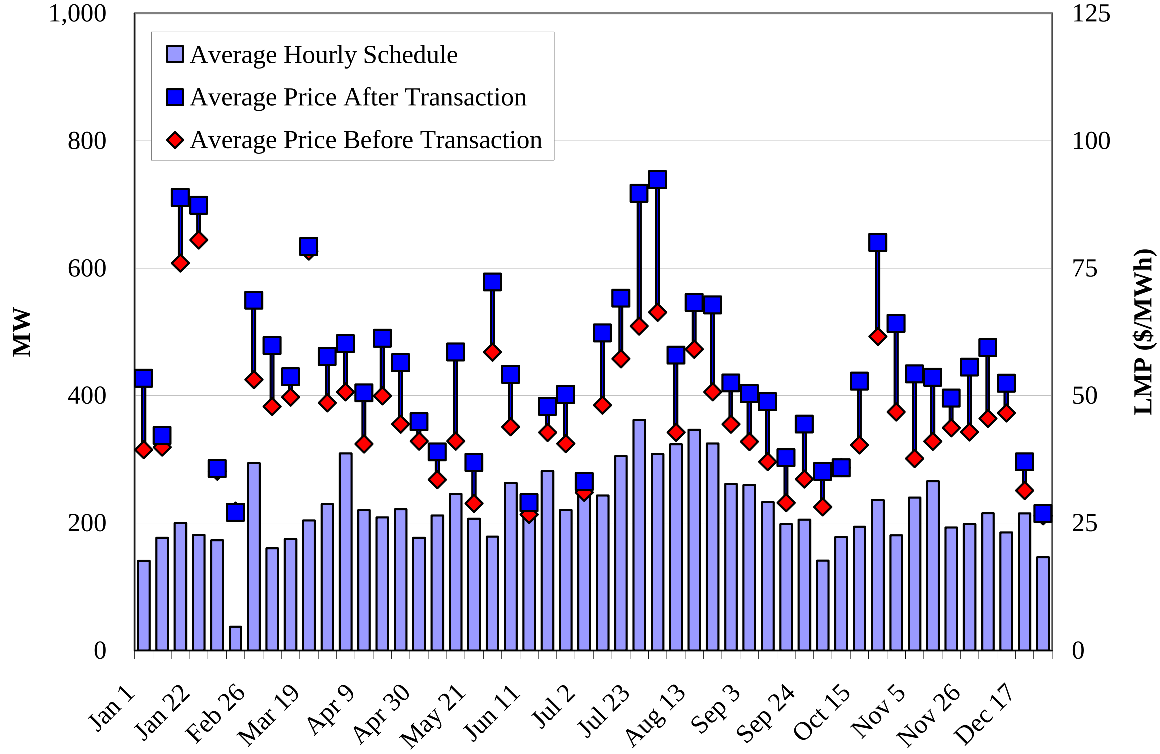
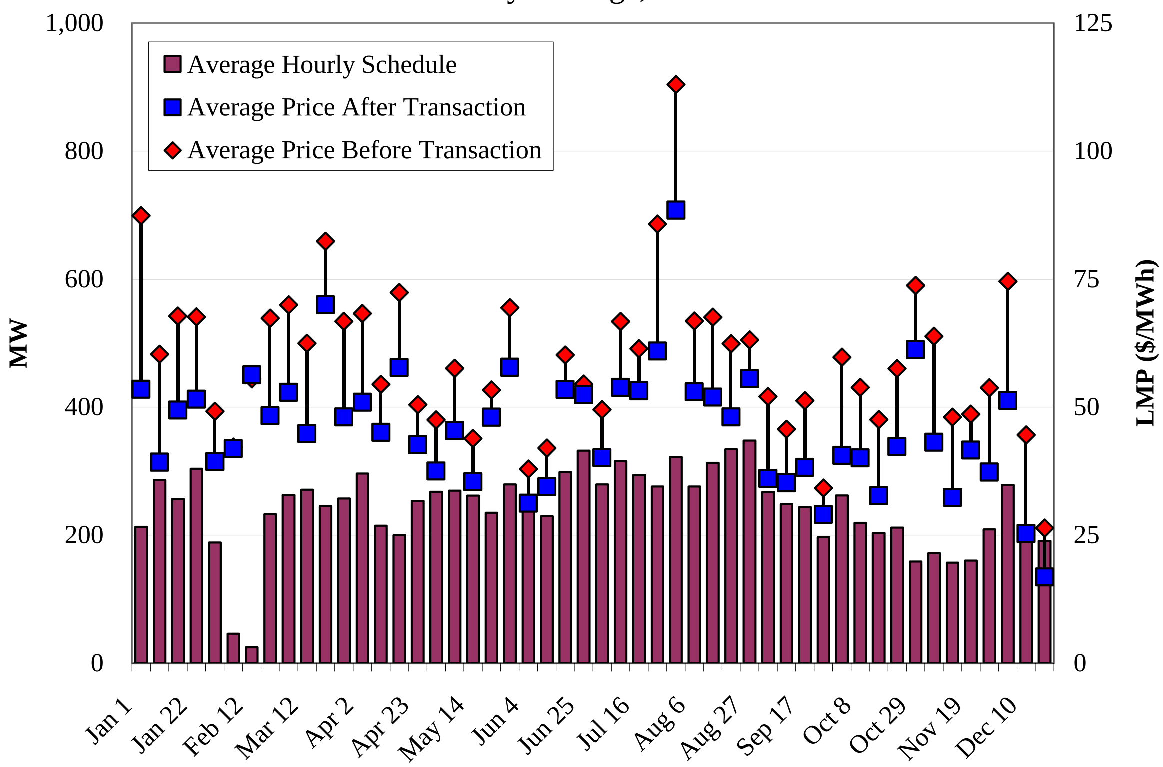


Figure 92: Intra-Hour Scheduling: Price Impact of Imports
Weekly Average, 2006



A key issue in our analysis concerns whether the intra-hour transactions were economically rational (i.e., profitable). Scheduling transactions unprofitably suggests that the participant was deriving other benefits from the transactions, which would raise market manipulation concerns. We focused on transactions between MISO and PJM, which form the bulk of the short-term transactions. Our evaluation focuses on the apparent profitability of the transactions based on differences in the 5-minute proxy prices for MISO and PJM. A participant scheduling a transaction between MISO and PJM would settle with each RTO and receive the difference in prices. Our analysis indicated that more than 70 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 half were ultimately profitable based on the hourly settlement.

Our findings regarding intra-hour transactions are that the overall level of intra-hour scheduling is modest and that the majority of 15-minute transactions appear to be rationale (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, there was not 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. Therefore, we recommend that the Midwest ISO consider the feasibility of settling intra-hour transactions on a 15-minute rather than hourly basis.

Our analysis also indicates that large NSI changes can result from the acceptance of intra-hour transactions under the Midwest ISO's current procedures. To address this issue and avoid incurring costs inefficiently to support very short-term transactions, we recommend the Midwest ISO limit its acceptance of such transactions based on its actual available capability to ramp internal generation up or down to support the transaction.