POTOMAC ECONOMICS

2005 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 our first full and detailed evaluation of the Midwest ISO energy markets that were introduced on April 1, 2005. These markets efficiently dispatch generation on the basis of supply offers to satisfy energy demand and operating reserve requirements, while preventing power flows on the network from exceeding transmission constraints. The markets establish 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 provide transparent price signals that 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 allow 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 introduction of the Midwest ISO energy markets was relatively smooth with no significant disruptions. This is significant given the expansive geographic scope of the Midwest ISO markets and the fact that it represented a fundamental transition from a decentralized wholesale market that relied on bilateral trading to a coordinated centralized set of wholesale energy markets.

We also found that the market performed very competitively in 2005. 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.

The introduction of the Midwest ISO energy markets is significant because they provide substantial benefits for the region. Although it is 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 Midwest ISO 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, and 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 is lagged and uncertain, which compels operators to be much more conservative 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. This may be the most significant benefit of the markets since the benefits accumulate over time as improved investment and retirement decisions are made. Unfortunately, this is also the least quantifiable of all of the benefits of the Midwest ISO's markets.

In addition to providing a summary of the prices, load, and other market outcomes in 2005, this report includes assessments of: the competitive performance of the markets; the operation of the day-ahead and real-time markets; the adequacy of the supply and economic signals provide by the markets; the management of congestion during 2005; and the coordination and transactions with adjacent areas. Our findings and recommendations in these areas are summarized and discussed below.

A. Energy Prices and Net Revenue in 2005

Prices in the Midwest ISO energy markets in 2005 were generally higher than they had been in prior years. These increases are not attributable to the introduction of the energy markets in April 2005, but rather to higher-than-expected demand associated with the relatively hot weather that prevailed during the summer and to substantial increases in natural gas and oil prices that occurred in the fall and winter of 2005.

With regard to the load, peak demand levels were significantly higher in 2005 than in prior years. Load exceeded 100 GW in 165 hours in 2005, versus 16 hours and 10 hours in 2004 and 2003, respectively. The relatively high prices generated under these conditions were significant contributors to the higher average prices in 2005.

However, prices were most heavily influenced by natural gas and oil prices. Natural gas prices increased by more than 66 percent in the fall and winter 2005 from the levels that prevailed in early 2005. These increases were largely due to the effects of the hurricanes on the production capability in the Gulf Cost region. The report shows that the Midwest ISO's energy prices are highly correlated to natural gas prices in the region. This correlation is expected since 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 most generators variable costs.

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. In a long-run equilibrium, the market should support the entry of new generation by providing average net revenues that are sufficient to finance new investment. This may not be the case in each year because there are random factors that can cause the net revenue to be higher or lower than the equilibrium value (e.g., weather conditions, generator availability, competing fuel prices, etc.).

The net revenue analysis shows that even in the highest-price region, Wisconsin-Upper Michigan ("WUMS"), a new natural gas-fired generator would not have earned net revenues sufficient to justify new investment. This outcome is not surprising given that:

- The Midwest ISO region continues to have substantial excess generating capability, which reduces net revenue from equilibrium levels.
- Net revenue high enough to support new entry requires either a significant number of price spikes associated with periods of shortage or capacity market revenues – the Midwest ISO had neither in 2005.
- The Midwest ISO currently lacks ancillary service revenues, which can provide substantial net revenue for combustion turbines that are called upon to produce energy in only a small share of the hours.

Once the excess capacity in the region declines, it will be important for the Midwest ISO to have markets in place to send efficient long-term signals to ensure a sustainable base of supply to meet the region's energy and operating reserve requirements. One important market enhancement that will contribute to satisfying this requirement is the introduction of ancillary services markets. 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 Midwest ISO is in the process of developing and implementing ancillary services markets in consultation with a broad array of stakeholders including Organization of the Midwest ISO States ("OMS"), the Balancing Authorities ("BA's"), and the Market Participants. The development of these markets should be among the Midwest ISO's highest priorities. The Midwest ISO is also working with these stakeholders to develop a plan for ensuring the resource adequacy requirements of the region.

B. Day-Ahead Market Performance

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

- The day-ahead market governs most of the generator commitments in the Midwest ISO – hence, efficient commitment requires efficient day-ahead market results.
- Most wholesale energy that is bought or sold through the Midwest ISO markets is settled in the day-ahead market.

- The entitlements of the FTRs are determined by the results of the day-ahead market (the payment to an FTR holder is based on the day-ahead congestion).

The Midwest ISO markets have substantially improved the commitment and dispatch of generating resources in the Midwest. The improved commitment is largely attributable to the day-ahead market. The day-ahead market provides a market-based process to commit generating resources and supply load – 97 percent of the generation dispatched to meet load is scheduled through the day-ahead market. On average, an additional 7 percent is committed after the day-ahead market by market participants (i.e., self-scheduling) and by the Midwest ISO to meet anticipated energy and reserve needs and manage congestion in real time (i.e., reliability assessment commitments).

One reason that the generation is not more 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. The modest under-scheduling of load was consistent with the price signals produced by the markets in 2005. When load is under-scheduled, it can lead to supplemental generator commitments that can reduce real-time prices, thereby reducing the incentive to buy in the day-ahead market. It is also consistent with the fact that peaking resources, which are often relied on in real-time to serve the incremental load, frequently do not set prices in the real-time market.

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. 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. This is encouraging because a liquid virtual market contributes to efficient results in the day-ahead market.

C. Real-Time Market Performance

The real-time market is important because it 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. 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.

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 on the day-ahead market. Nonetheless, prices in this market should converge well 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. The most substantial congestion was between Minnesota and the WUMS area where the average difference in prices exceeded $15 per MWh. Under the bilateral markets that had prevailed prior to the introduction of the Midwest ISO energy markets, this congestion was 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 25 percent of the generators' capacity – 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.

Revenue sufficiency guarantee ("RSG") payments are made to ensure 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. RSG costs averaged more than $50 million per month in 2005.[1] These costs can be caused by inefficient or excess commitment of non-peaking resources – our analysis did not show that this was a problem.

Peaking resources received approximately 75 percent of the RSG payments, despite producing only 2 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 improved its commitment and dispatch of peaking resources substantially over the first year of its market operation.

To achieve further improvements, we have recommended 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-run, 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 the system's needs. We have also consulted with the Midwest ISO regarding of number of other provisions it has proposed that should improve system flexibility and reduce RSG payments.

D. 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. The LMP markets reduced the need to rely on TLR curtailments of wholesale transactions, which decreased by 75 percent from 2004 to 2005.

1 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.

Congestion costs in the day-ahead and real-time markets were almost $800 million in 2005. Higher natural gas prices in the fall increased the costs of congestion in the second half of the year because they increased the costs of re-dispatching generation to manage congestion. The report also shows that a large share of the increase in congestion in late 2005 was due to increased congestion into WUMS and on the path to TVA. 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 has subsequently taken initial steps to coordinate this service with the Midwest ISO, but we recommend in the longer-run that the RTOs coordinate this export service under the market-to-market provisions of the Joint Operating Agreement ("JOA").

Finally, the real-time energy market did not have sufficient capability to redispatch generation to manage the transmission congestion in a number of cases. 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.

E. Financial Transmission Rights

Financial transmission rights provide a hedge for congestion because the day-ahead congestion revenue over the path that defines the FTR is paid to the FTR holder. Financial Transmission Rights ("FTRs") were fully funded in 2005. In other words, sufficient congestion costs were collected to pay the full amount obligated to the FTR holders. On a monthly basis, however, the FTRs were under-funded in the last 3 months of 2005. In these months, the under-funding was due to a) loop flows that were not fully reflected in the FTR modeling and b) significant transmission outages.

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 6 percent of the total payments. This is good 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 April 2005 were generally well above the value of the congestion. After April, FTR prices generally adjusted relatively quickly to changes in congestion patterns from prior months. The pricing of FTRs should continue to improve over time as participants gain experience with the market.

F. 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 3500 MW in on-peak hours and close to 2000 MW in off-peak hours. More than half of these imports come from Manitoba. The Midwest ISO is also a net importer from PJM, although the power flows across this interface frequently reverse direction.

When the markets were first introduced, the net imports were lower than they had been pre-market. Additionally, in the first 45 days of market operation, the real-time net imports were often substantially less than the day-ahead net imports. This raises potential reliability concerns because it can cause the generator commitments made day-ahead to be inadequate, leading to a relatively heavy reliance on peaking units. After the first 45 days, the real-time net imports became much more consistent with the day-ahead net imports.

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 JOA to optimize the net interchange between PJM and the Midwest ISO.

The report also evaluates the market-to-market coordination 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. These refinements include optimizing the relief requested by each RTO and changing how LMPs affected by the market-to-market constraints are calculated.

G. 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 2005.

Although reliable inferences regarding market power cannot be drawn from market concentration statistics, the report indicates that concentration is low for the overall the Midwest ISO area, but quite high in the East, West, and WUMS sub-regions. The top three suppliers control 70 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 80 percent of the hours when load exceeds 60 GW (this represents 75 percent of all hours).
- The West and East regions exhibit a pivotal supplier in a substantial portion of the hours when load exceeds 80 GW (20 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. More than one third of the active "broad constrained area" ("BCA") constraints have a pivotal supplier. BCAs are all constraints other than those into and within WUMS. Almost 60 percent of the active "narrow constrained area" ("NCA") constraints have a pivotal supplier. NCAs are currently designated to include the constraints into or within WUMS.

In addition, as a percent of all intervals during 2005, 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 almost 30 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 as constraints arise and include all of the generating units that have a significant impact on the power flows over the constrained interface.

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 24 instances and for NCA constraints in 62 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. Such mitigation occurred on 42 unit-days and reduced RSG costs almost $6 million.

The moderate levels of mitigation related to RSG payments were due to the fact that suppliers with local market power generally did not attempt to exercise market power. In fact, we have estimated the Midwest ISO's exposure to higher RSG costs if participants with local market power in BCAs (i.e., those that are pivotal) were to have submitted $1 million dollar start-up and no-load offers in 2005. Actual real-time RSG costs exceeded $500 million in 2005. However, if pivotal suppliers in BCAs had engaged in the conduct described above, the additional RSG costs would have been almost $2.8 billion. We have reviewed these costs and can confirm that they are largely incurred when specific reliability issues arose in 2005 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.

H. Summary of Recommendations

In its first year of operation, the Midwest ISO's market has 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:

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

- Complete and implement the full ARC procedures that allow the Midwest ISO operators to activate and dispatch the reserve range on units (output above EcoMax) – it will lower costs and allow a means for the market to set efficient prices during shortages.

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

- 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 costs.

- To increase the redispatch options and, hence, the manageability of certain transmission constraints, we recommend a) the real-time market model be modified to allow generating resources with lower impacts on the constraints to be redispatched; and b) mitigation measures be applied prospectively to the physical offer parameters when generator inflexibility causes substantial congestion.

- When a transmission constraint is unmanageable, we recommend the Midwest ISO use the constraint penalty factor to set the nodal energy prices. This is particularly important for the market-to-market constraints.

- We recommend the Midwest ISO consider modifying the JOA with PJM to:
  - Adjust the amount of relief each RTO requests from the other RTO;
  - Optimize the real-time net interchange between the two RTO areas; and
  - Develop a process under the JOA to coordinate exports to other non-RTO areas.

The Midwest ISO is evaluating these recommendations and we will be available to consult with the 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.

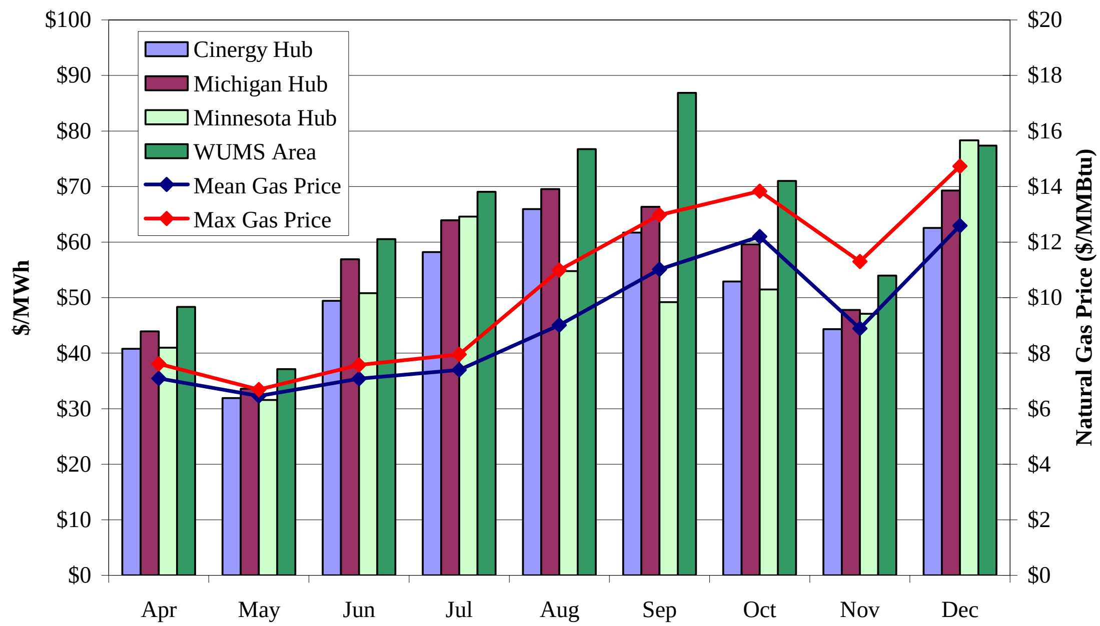
II. Prices and Revenues

The Midwest ISO introduced competitive wholesale electricity markets on April 1, 2005. These markets 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 initial outcomes of these markets in 2005. In this first section, we summarize and evaluate the prices and revenues in the Midwest ISO markets.

A. Overview of Prices and Fuel Costs

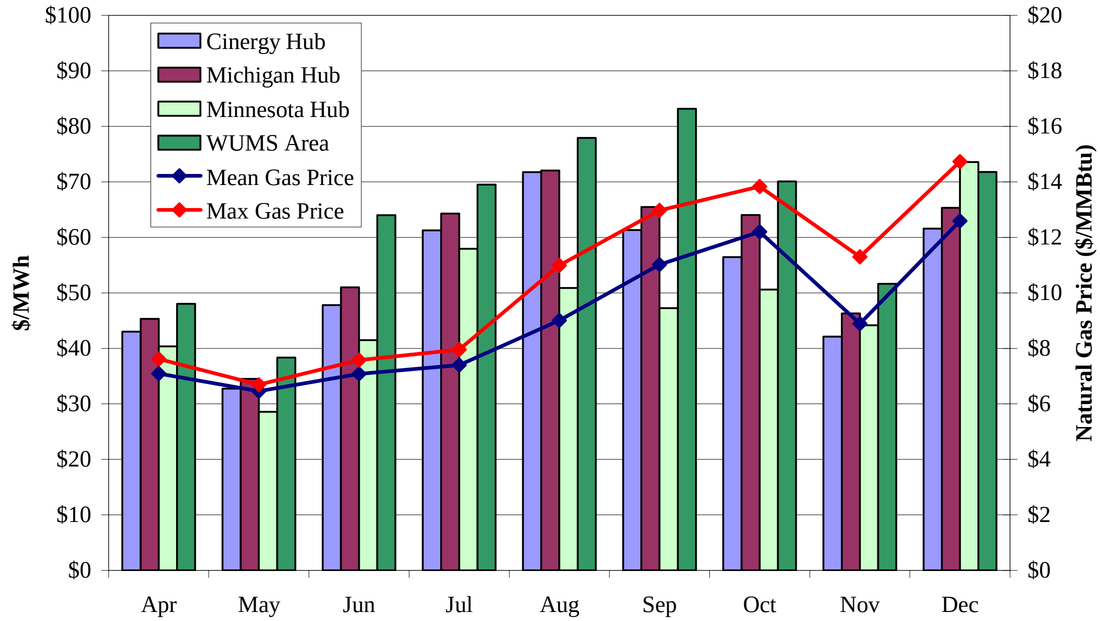
We begin our analysis of the market results by providing an overview of the electricity prices and fuels prices for the Midwest ISO markets. Our first analysis is shown in the following two figures. Figure 1 shows the average monthly day-ahead energy prices for three of the Midwest ISO pricing hubs and for the WUMS area.[2] It also shows the monthly average and maximum natural gas prices in each month. Figure 2 shows the same analysis for the real-time market.

Figure 1: Day-Ahead Average Monthly Hub Prices
2005: All Hours



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

Figure 2: Real-Time Average Monthly Hub Prices 2005: All Hours

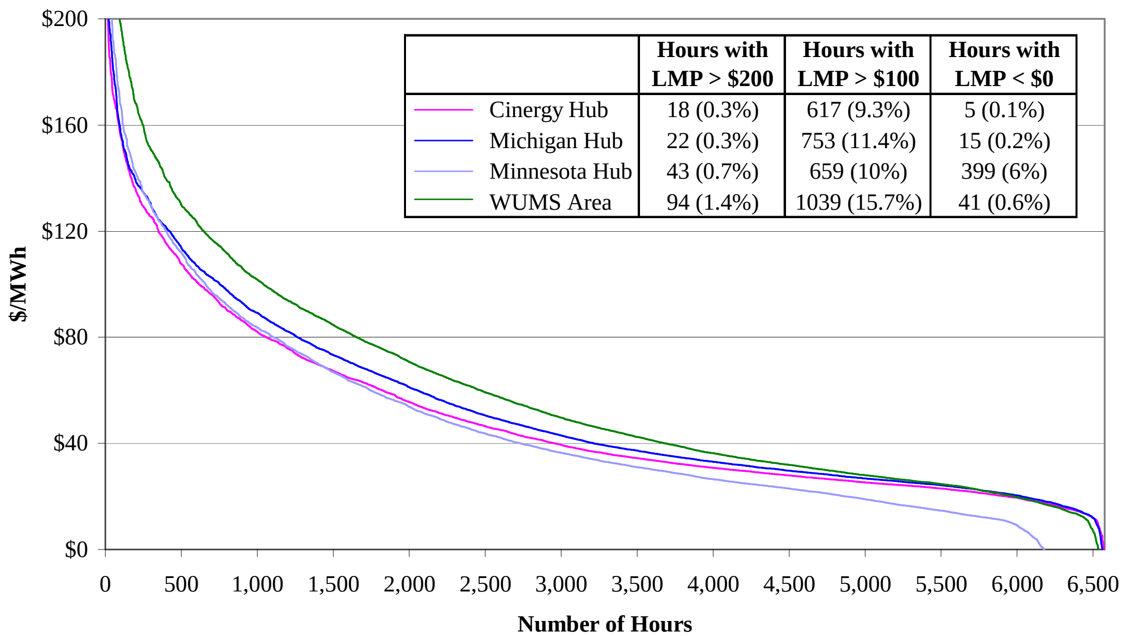


Both figures show that changes in fuel prices were a primary contributor to the fluctuations in electricity prices in 2005. Natural gas prices increased substantially after the summer, rising to levels by December that were 66 percent higher than in January 2005. These increases in natural gas prices were primarily due to hurricanes that reduced the supply of natural gas from the Gulf Coast region in the fall of 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 the incentive to offer their energy at its marginal costs. Hence, as fuel costs rise, generators' offer prices should rise. Although only about 30 percent of the resources in the Midwest ISO region are 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.

The figures also show the transmission congestion between the hubs. Significant price differentials between hubs generally indicate transmission congestion, although locational price differences can also be caused by transmission losses. The most significant price differential is between Minnesota and WUMS because the most frequently binding transmission constraints are those that limit imports into the WUMS area from the western and southern directions. On average, the WUMS price exceeds the price at the Minnesota hub by almost $16 per MWh in the day-ahead market and by $17 per MWh in the real-time market. While the Minnesota to WUMS congestion pattern is one of the most common transmission constraints in the Midwest ISO region, outages and other system conditions can cause substantial transitory changes in congestion patterns. This occurred in December when an ice storm and the simultaneous outages of a key transmission facility and baseload generation in Minnesota reversed the patterns of congestion and caused prices to be higher in Minnesota than in WUMS.

Our next analysis evaluates the hourly prices in the real-time market. Figure 3 shows a real-time price duration curve 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 $80 per MWh level at approximately the 1000 hour level on the x-axis. This indicates that in approximately 1000 hours from April to December 2005, the Cinergy hub price exceeded $80 per MWh.

Figure 3: Real-Time Price Duration Curve
2005: All Hours



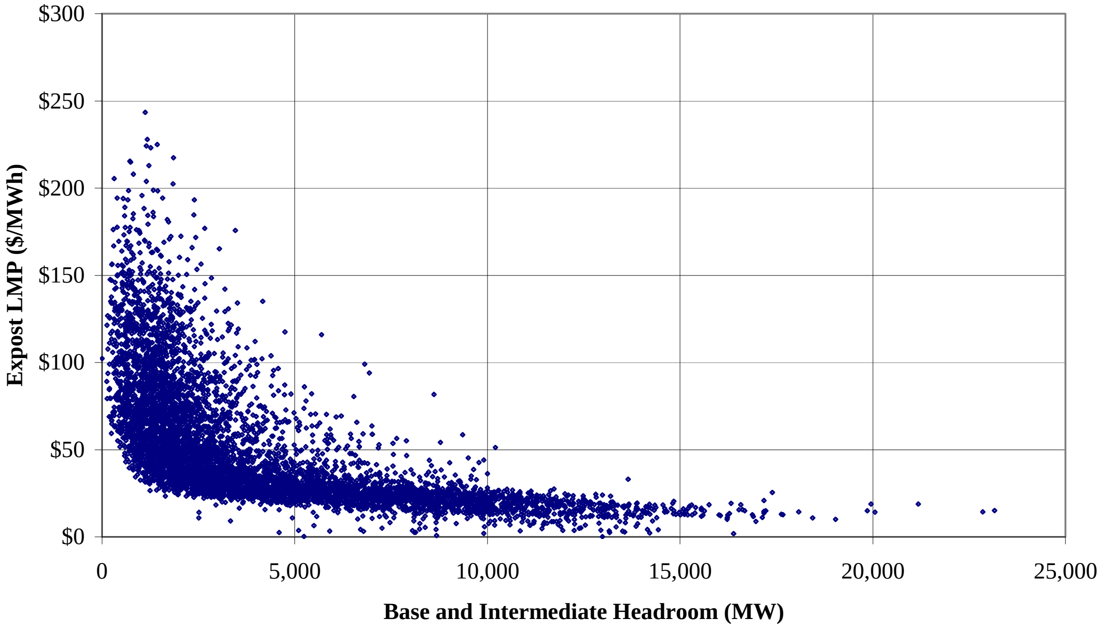
The differences between these curves are due to congestion and losses that cause prices to vary by location. The WUMS prices are the highest due to the frequent congestion into that area -- 15 percent of the hours exhibit prices above $100 per MWh and 1.4 percent of the hours have prices above $200 per MWh. Michigan is the next highest-priced region with 11 percent and 0.3 percent hours above $100 per MWh and $200 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 addition to causing high prices in the WUMS area, congestion into WUMS lowers prices in the Minnesota area where average prices are the lowest in the Midwest ISO region. In 6 percent of the hours, congestion was severe enough to cause prices to be negative in Minnesota. In general, this occurs when the Midwest ISO has difficulty managing the congestion into WUMS due to limited:

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

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 4 shows the relationship between headroom on baseload and intermediate generating resources in the real-time market.

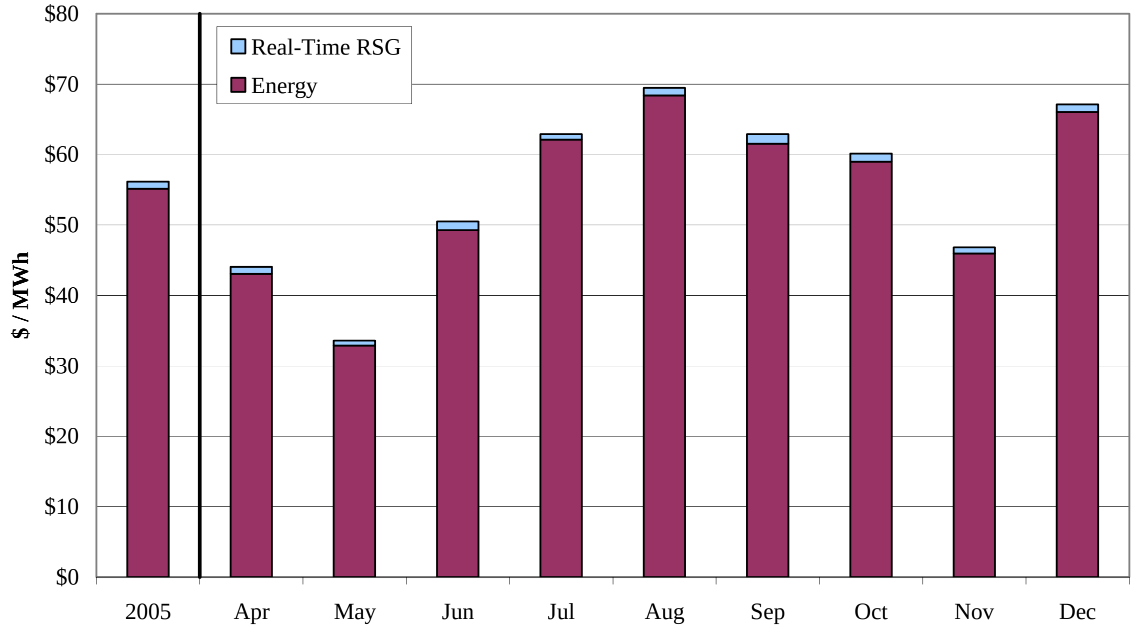
Figure 4: Relationship of Base & Intermediate Headroom to Price Real-Time Market: All hours



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, which indicates that economic withholding has not been a significant problem in 2005.

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 is a metric that 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. The all-in price of the Midwest ISO wholesale electricity is shown in Figure 5.

Figure 5: All-In-Price of Wholesale Electricity 2005



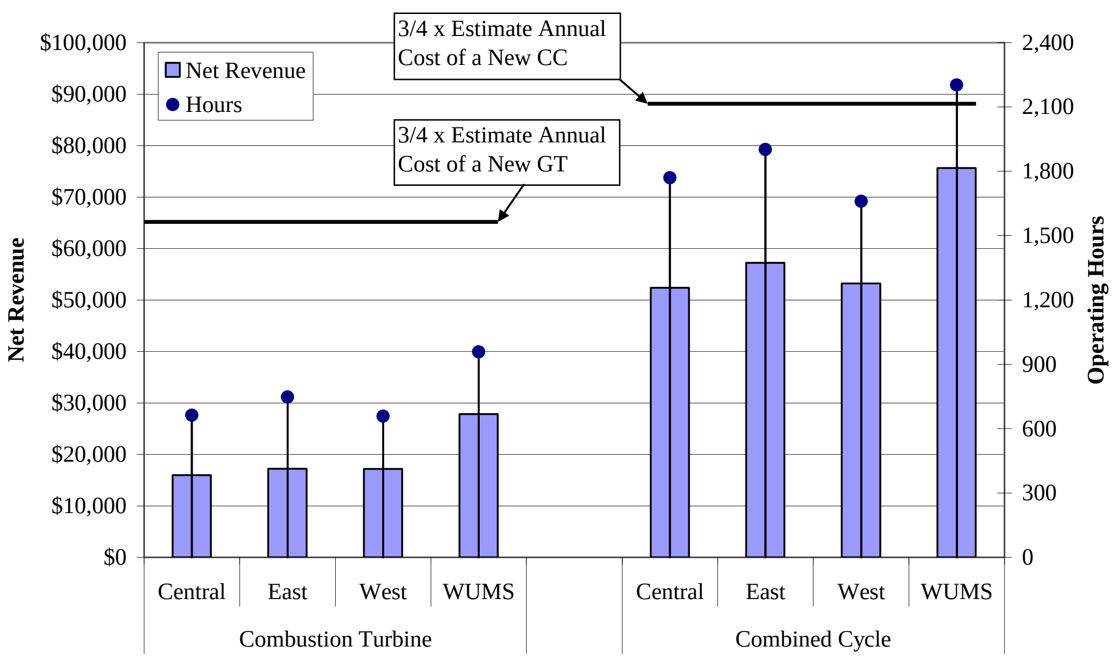
This analysis shows that RSG costs are a very small share (less than 2 percent on average) of the all-in price. The all-in price was highest during the peak load months of the summer. However, it was substantially affected by higher natural gas prices that occurred after the hurricanes in the fall 2005. This subsection has provided a summary of the prices that occurred in the Midwest ISO energy markets during 2005 while the next subsection evaluates the economic signals provided by these prices to market participants.

B. Net Revenue Analysis

The economic signals provided by the Midwest ISO markets can be assessed 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. In long-run equilibrium, the market should support the entry of new generation by providing average net revenues that are sufficient to finance new investment. This may not be the case in each year because there are random factors that can 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 do not include capacity or ancillary services markets.

Therefore, our analysis only includes net revenues that could have been earned in the Midwest ISO market over the first nine months of operation. 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. 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 6 together with the number of hours each type of unit would be estimated to run.

Figure 6: Net Revenue and Operating Hours



Because combined cycle generators have a substantially lower production costs than simple-cycle combustion turbines, the figure shows that they run more frequently (roughly 20 percent all hours in most locations and almost 30 percent in WUMS) and generate higher net revenues, which range from more than $50,000 to $75,000 per MW-year. The net revenues for the combustion turbine range from $15,000 to $30,000 and a new combustion turbine would be expected to run in approximately 10 percent of the hours in WUMS and only slight above 5 percent of the hours in the other regions. 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 2005.

The figure also shows the annualized cost a new unit (i.e., the annual net revenue a new unit would need to earn to make the investment economic), prorated at 75 percent to account for the fact that the net revenues results include only the last 9 months of 2005. The net revenue analysis shows that even in the highest price region (WUMS), neither a CT nor CC unit would have earned net revenues sufficient to justify new investment. For the following reasons, this outcome is expected.

- The Midwest ISO region continues to exhibit substantial excess generating capability. Excess capacity lowers net revenue by reducing prices whereas relatively low capacity margins can cause net revenue levels to substantially exceed the annualized cost of a new unit.
- Net revenue high enough to support new entry requires either a significant number of price spikes associated with periods of shortage or capacity market revenues. As noted above, the Midwest ISO has no capacity market.
- Ancillary service revenues can provide substantial net revenue for combustion turbines that are called upon to produce energy in only a small share of the hours.
- Higher than expected gas prices during 2005 limited the economic run hours of gas-fired capacity in the Midwest ISO.

Once the excess capacity in the region declines, it will be important for the Midwest ISO to have markets in place to send efficient long-term signals to ensure a sustainable base of supply to meet the region's energy and operating reserve requirements. One important market enhancement that will contribute to satisfying this requirement is the introduction of ancillary services markets. 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 Midwest ISO is in the process of developing and implementing ancillary service markets in consultation with a broad array of stakeholders including Organization of the Midwest ISO States ("OMS"), the Balancing Authorities ("BA's"), and the Market Participants. The development of these markets should be among the Midwest ISO's highest priorities. The Midwest ISO is also working with these stakeholders to develop a plan for ensuring the resource adequacy requirements of the region.

III. Load and Resources

Understanding the fundamental supply and demand conditions in the Midwest markets is important in assessing the Midwest ISO markets, which began operations in April 2005. 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.

The Midwest ISO is the independent operator of the regional transmission network comprised of the transmission facilities of the Midwest ISO transmission owners. Transmission-owning members have transferred control of their transmission facilities either as signatories to the FERC-approved Midwest ISO OATT or as participants in Independent Transmission Companies that are members of the Midwest ISO under Appendix I of the Midwest ISO Agreement.

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. 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:

(1) East – generally includes the Midwest ISO control areas that had been located in the NERC ECAR region;

(2) West – generally includes the Midwest ISO control areas that had been located in the NERC MAPP region;

(3) 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

(4) WUMS -- the Midwest ISO control areas located in the WUMS region.

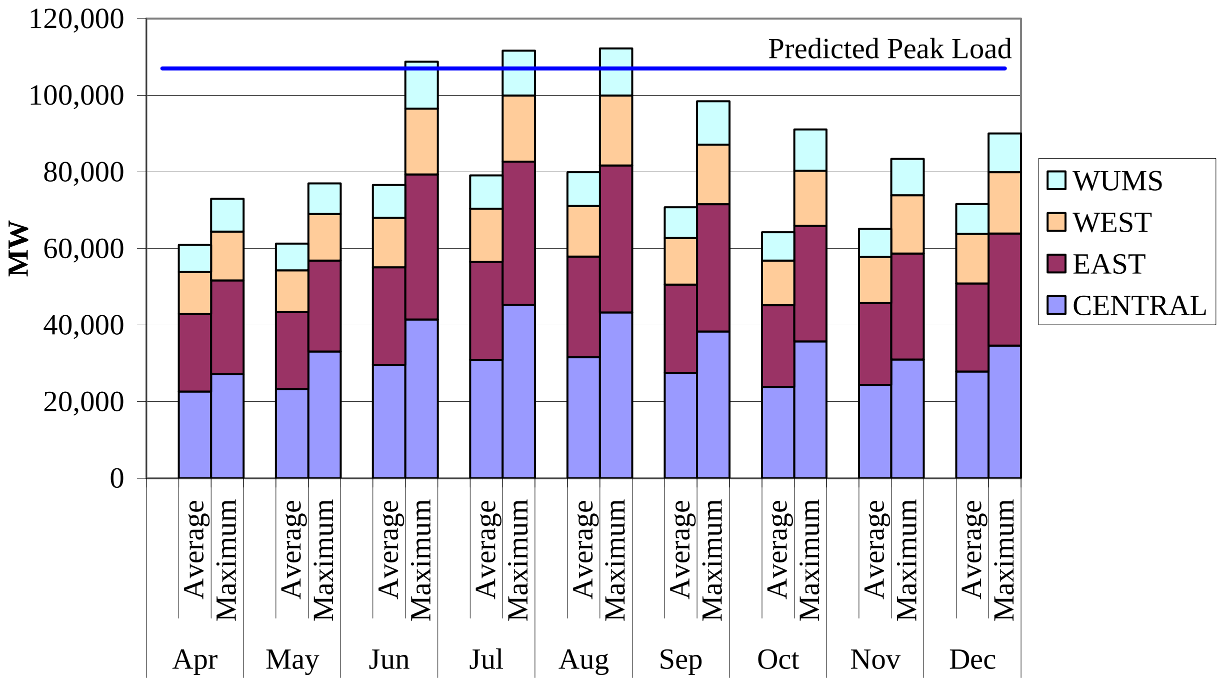
There are over 60 owners of generation resources in the Midwest ISO footprint as defined by the set of Midwest ISO control areas. This includes large investor-owned utilities, municipal and cooperative utilities, and independent power producers. Generation owned by non-transmission owners (e.g., municipal 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.

It should be emphasized that these four sub-regions should not be viewed as distinct geographic markets. This is particularly important for the data presented below concerning market concentration in these sub-regions. Therefore, the market concentration in these sub-regions does not allow one to draw reliable competitive conclusions. An accurate market power analysis would require substantially more analysis beyond calculating market shares 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 7.

Figure 7: Monthly Maximum and Average Load 2005



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 June, July and August, the peak load was 109 GW, 112 GW, and 112 GW, respectively. Each of these monthly peaks was well above the predicted peak load for 2005 of 107 GW, which is shown by the blue horizontal line in the figure.

The figure also shows the peak load levels are substantially higher than average load levels as is characteristic of electricity markets. During the summer months, the peak load levels were 40 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 levels by providing load duration curves for 2003, 2004, and 2005. 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 similar to the price duration curves shown in the prior section of the report. This analysis is shown in Figure 8.

Figure 8: Load Duration Curves
2003 - 2005

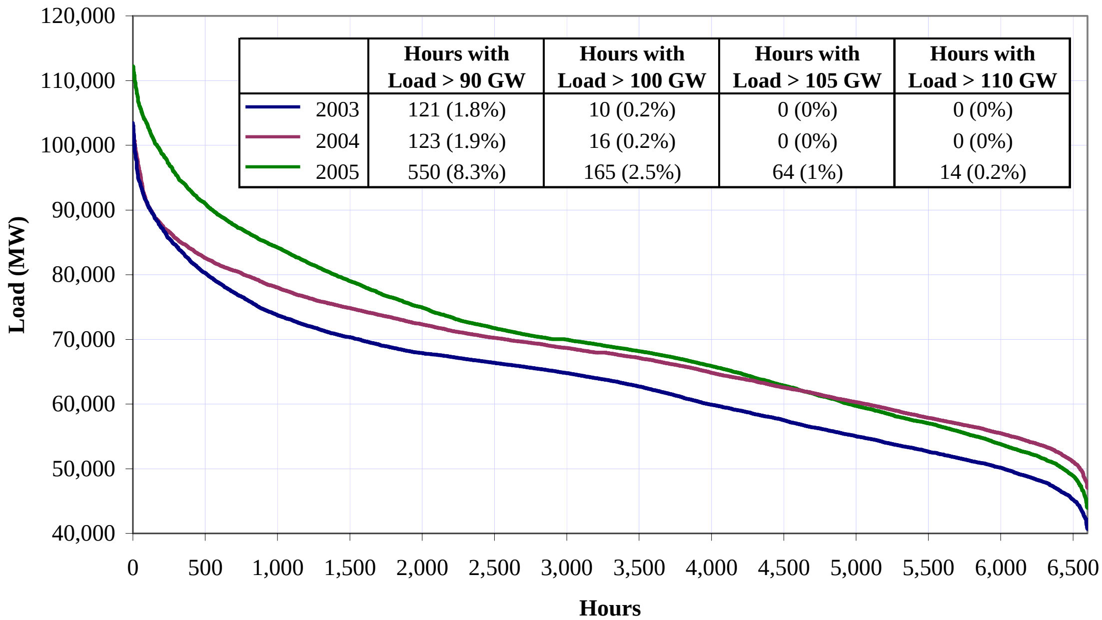


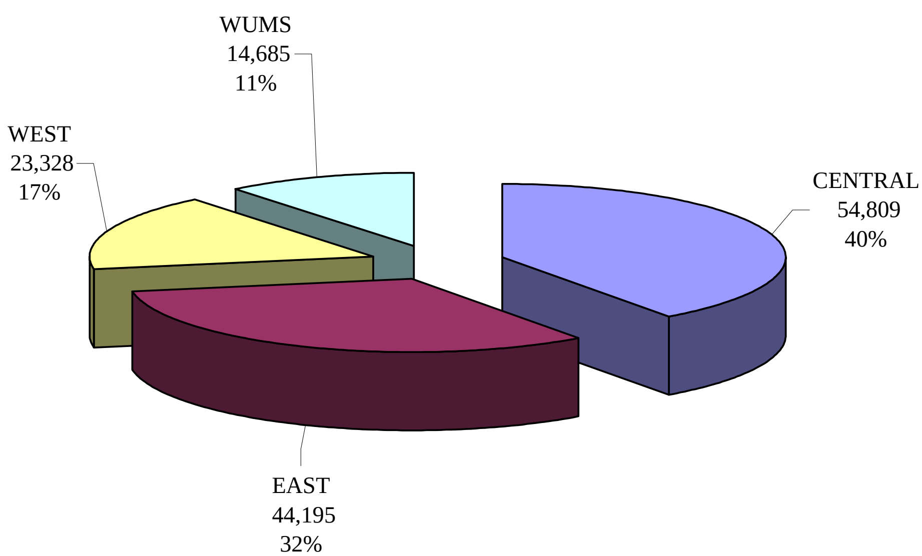
Figure 8 shows that there were significantly more hours exhibiting extreme demand levels in 2005 than in prior years. In particular, there were 14 hours when actual loads exceeded 110 GW, but no such hours in 2004 or 2003. In 2005, there were 165 hours when actual loads exceeded 100 GW versus 16 such hours in 2004 and just 10 hours in 2003. These peak demand conditions were primarily due to the relatively hot temperatures that occurred during the summer 2005, which led to higher air conditioning loads than predicted. This is consistent with the load levels in other regions where weather-related loads were also substantially higher than predicted.

This figure also shows how much higher loads are during peak load hours than most other hours. More than 25 percent of the generating resources in the region are needed to serve the highest 5 percent of load and provide operating reserves. These resources necessarily operate in a small portion of the hours, which indicates the importance of setting efficient prices during the highest load conditions.

B. Generation Capacity

Generating resources in the Midwest ISO market footprint totaled 137 GW in 2005. Figure 9 shows the distribution of this capacity by coordination region.

Figure 9: Generation Capacity by Coordination Region



The capacity in the figure includes only that which is owned by the Midwest ISO market participants and excludes the Midwest ISO members that are only reliability members. Including the resources of the reliability-only members, the total generating capacity would increase to 170 GW.

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 9 shows that more than 70 percent of the generating resources are located in the East and Central sub-regions. Our next analysis shows the distribution of generating capacity by fuel type. This analysis is presented in Figure 10.

Figure 10: Distribution of Sub-Region Generation Capacity By Fuel Type

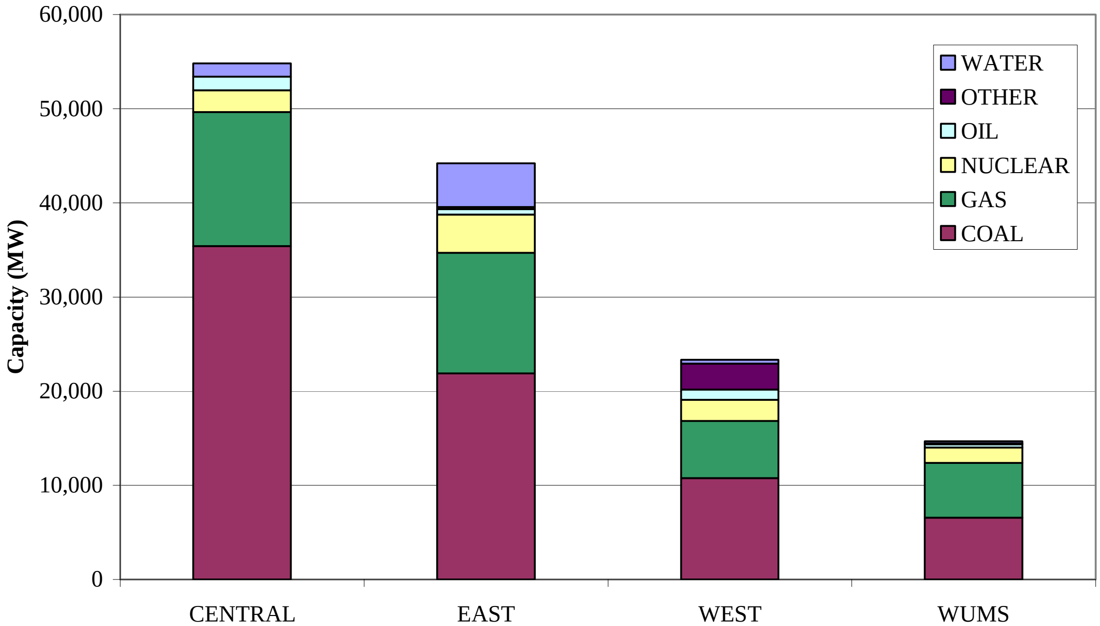


Figure 10 shows that the Midwest ISO relies heavily on coal-fired generating resources. Approximately 55 percent of its generation capacity is coal-fired. Because coal units are generally baseloaded, coal-fired resources produce an even larger proportion of the energy generated. The next largest category of capacity is natural gas-fired capacity, which represents about 30 percent of the generating resources in the Midwest. Because natural gas-fired resources are higher-cost than most of the other resources in the Midwest, they produce less than 30 percent of the energy in the region. Nevertheless, they frequently set the price in the Midwest ISO markets.

Nuclear plants provide approximately 7 percent of the capacity, while oil and hydro plants represent approximately 2 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.

The peak load in each sub-region must be satisfied by a combination of generating resources within the region or imports. Hence, it is instructive to present the resource margin for each sub-region. To do so, we calculate the ratio of the generation and net firm imports to the peak load for each region. Table 1 summarizes this analysis, showing each sub-region's generation capacity, net firm imports, peak load, and the resource margin that these values produce.

Table 1: Resources and Load in the Midwest

Midwest ISO Region	Generating Capacity	Net Firm Imports	Load	Resource Margin
Central	54,809	353	45,504	21%
East	44,195	2,409	38,397	21%
West	23,328	1,063	18,653	31%
WUMS	14,685	1,184	12,524	27%
Total	137,016	5,009	115,078	23%

Note : Net Firm Imports are based on data from the *2005 MAIN Summer Assessment,2005 ECAR Summer Assessment,* and the *2005 NERC Summer Assessment* .

The resource margins presented here are broad indicators of the adequacy of the resources in these areas, which can be useful for identifying potential areas of concern. In our analysis, Generating Capacity and Net Firm Imports do not reflect demand-side resources.[3]

Table 1 shows that each of the Midwest ISO sub-regions have substantial firm resources with resource margins generally ranging between 20 percent and 30 percent. In general, these capacity margins are higher than would generally be expected in a long-run equilibrium. This finding is consistent with the early results showing that the economic signals currently being provided by the Midwest ISO's markets would not support new investment. One reason for the

3 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.

high capacity margins is the significant net additions of resources in certain areas, which is shown in Table 2.

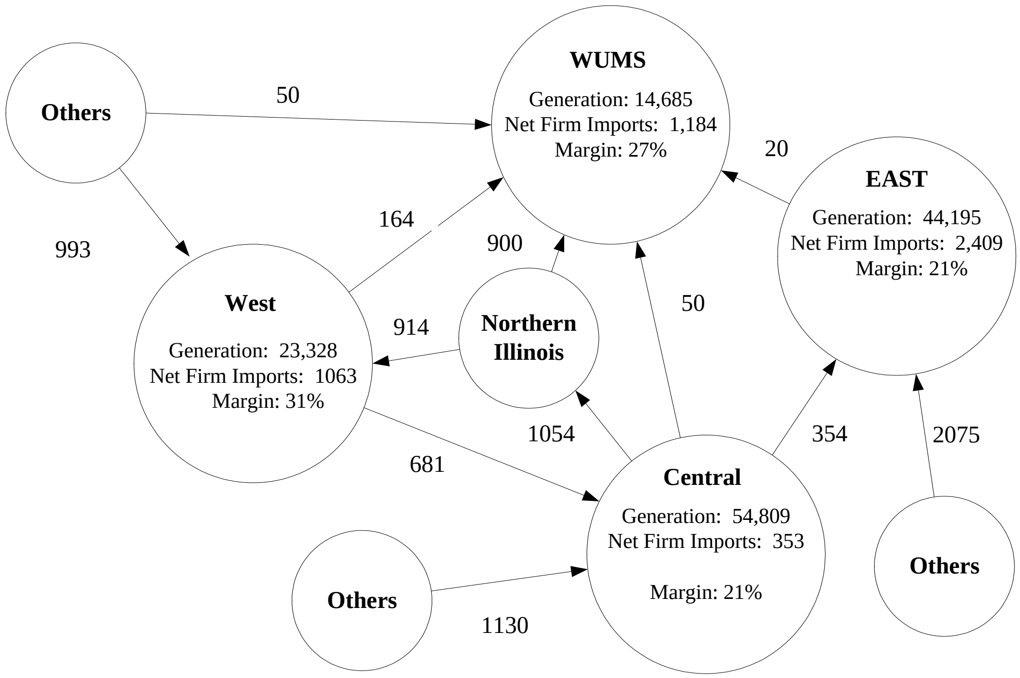
Table 2: Additions and Retirements

Midwest ISO Region	Additions	Retirements	Net Change
Central	135	13	122
East	24	-	24
West	1,301	16	1,285
WUMS	1,166	-	1,166
Total	2,626	29	2,597

The Midwest ISO footprint extends over a relatively broad area and is heavily interconnected to adjacent regions. To provide more detail on resource margins and the external sources of supply to the Midwest ISO region, Figure 11 shows a graphical representation of the interconnections between the Midwest ISO sub-regions and its interconnections with neighboring regions. For each of the sub-regions, this figure shows the generating resources, the firm net imports, and the resource margin. The values shown on the arrows between the sub-regions in this figure show the firm net imports.

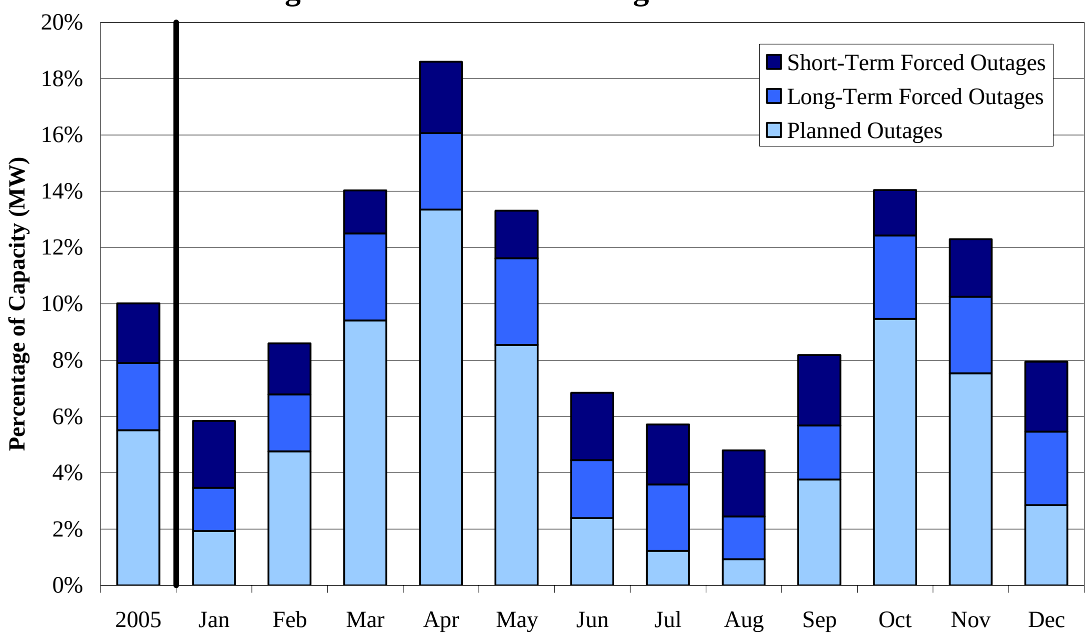
This figure shows that each of the sub-regions relies to some extent on firm imports and that the Midwest ISO region as a whole is a large net importer of firm power. The figure also shows that the WUMS sub-region relies more heavily on imports than any other sub-region. Because a substantial amount of new generation was added in 2005 in the WUMS area, however, this is the first year that it would have a resource margin of more than 15 percent without its net firm imports.

Figure 11: Summary of Resource Margin and Interregional Transfers



While the previous analysis examined capacity relative to the peak load requirements of the region, the availability of this capacity is also a major market factor. Accordingly, we next examine generator plant outages. Figure 12 shows the different types of generator outages on a monthly basis.

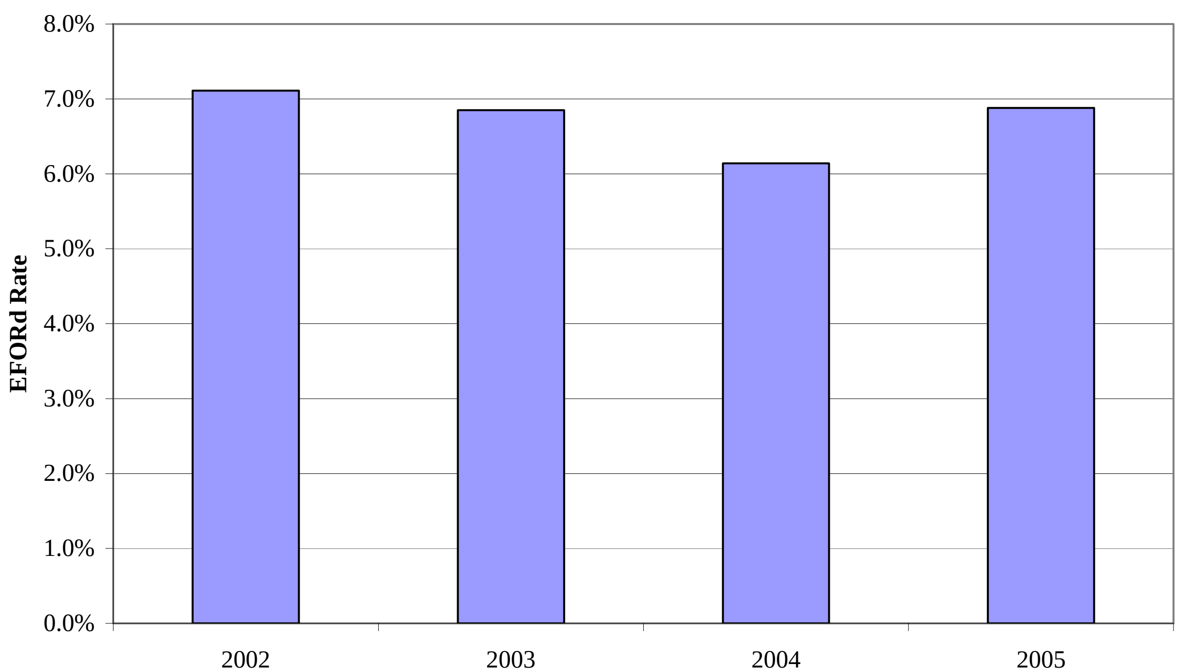
Figure 12: Generator Outage Rates in 2005



The figure shows only full outages – it does not include partial outages or deratings. The figure separates forced outages between short-term (less than 7 days) and long-term (longer than 7 days). The annual combined outage rate was 10 percent for the three categories of outages. As expected, this figure shows that the largest total outage levels occurred in the spring and fall because planned outages are generally scheduled during these times. Planned outages exceeded 10 percent during the spring and 7 percent in fall. Total planned and forced outages peaked in April at more than 18 percent. Planned outages were very small in the peak load months of July and August.

The forced outage rate did not substantially increase during the summer -- it remained at the annual average of 4 percent. This provides a preliminary indication that physical withholding via claimed forced outages was not a substantial concern in 2005 because the incentives to do so would be the highest during tight conditions during the summer. However, the competitive assessment section of this report provides a much more detailed evaluation of potential physical withholding. As a further summary of the outage rates in 2005, Figure 13 shows the Equivalent Forced Outage Rate-Demand ("EFORd") rates for 2002 through 2005.

Figure 13: Equivalent Forced Outage Rate-Demand



The data in this figure are unweighted values that are 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 accounts for both full outages and partial outages.

Figure 13 shows that forced outage rates from 2002 to 2005 period has been fairly consistent, from a maximum of 7.11 percent in 2002 to a minimum of 6.14 percent in 2004. The slightly higher EFORd rate in 2005 versus 2004 would only be a cause for concern if it indicated that physical withholding was a problem in 2005. Based on our analysis in the competitive assessment section of this report and day-to-day monitoring of market conduct, we do not find evidence of significant physical withholding in 2005.

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 convergence 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. Based on our analysis, we provide a number of suggested improvements that should enhance efficiency and the overall performance of the markets.

A. Day-Ahead Market Performance

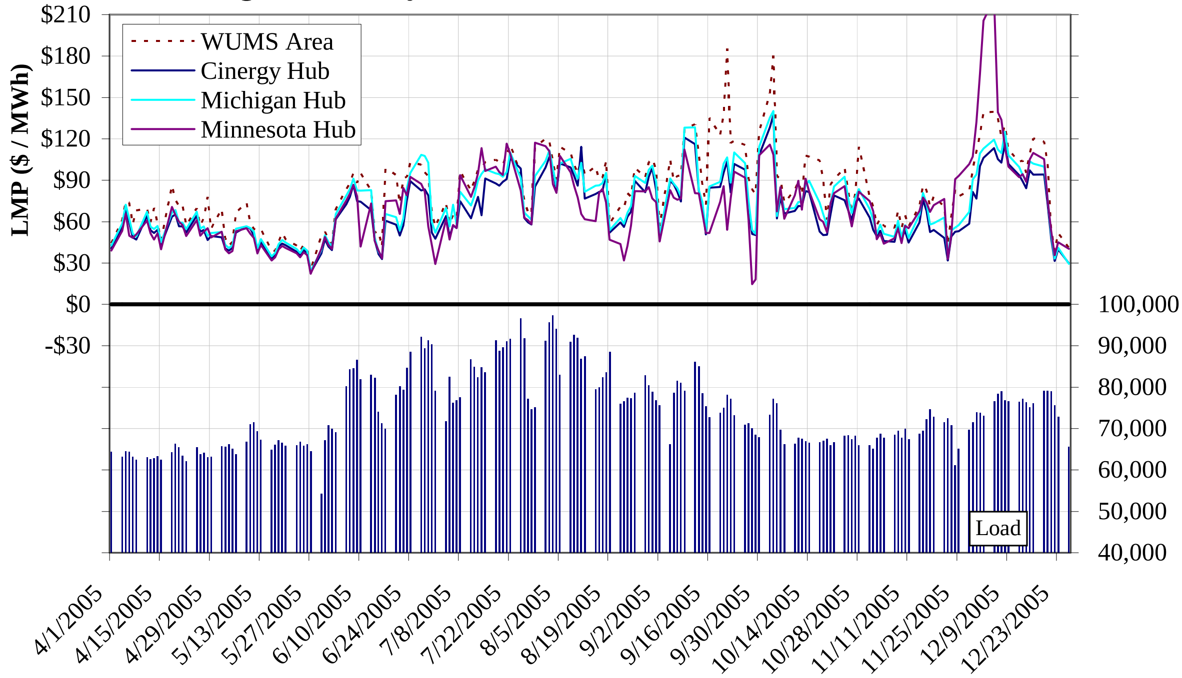
We begin this section by evaluating the performance of the day-ahead markets. The day-ahead market allows participants to make forward purchases and sales of power for delivery in the real-time. This is a valuable financial mechanism that allows participants to hedge their portfolios and manage risk.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

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 the day-ahead market results is shown in Figure 14.

Figure 14: Day-Ahead Hub Prices and Load -- Peak Hours

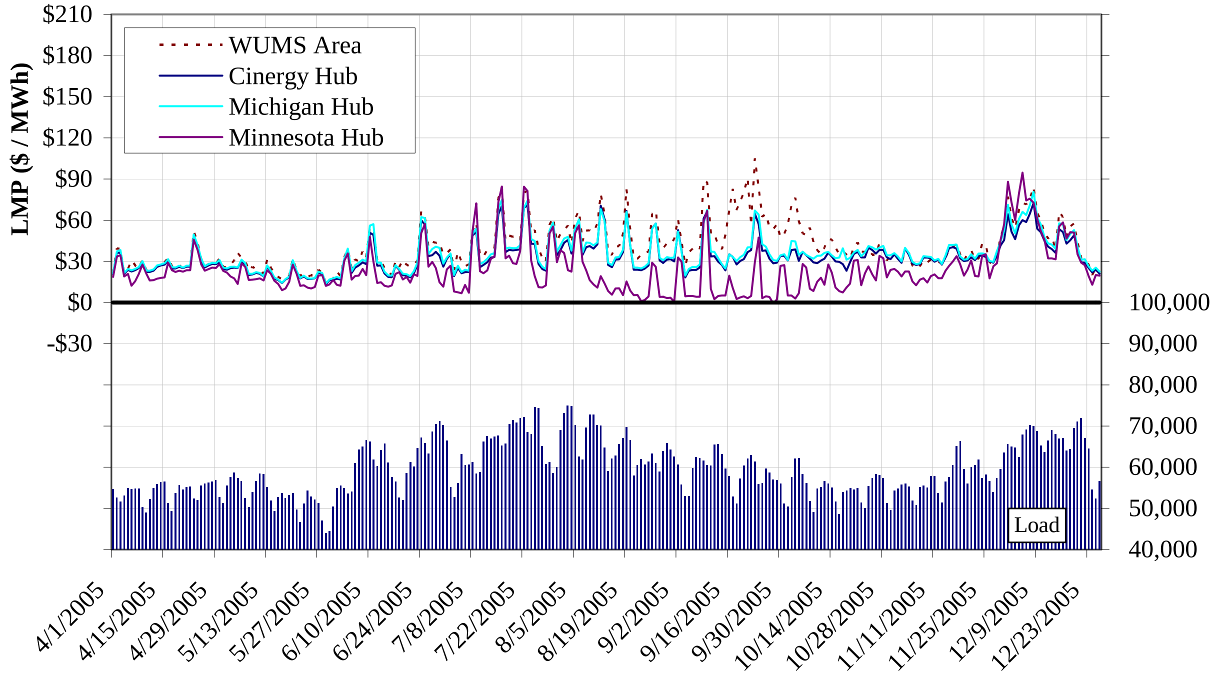


The figure shows the expected general correlation between peak loads and peak prices, with some exceptions. The highest prices occurred in congested areas during periods of congestion, a number of which occurred in the fall and winter under moderate load conditions. Gas prices began increasing in July and remained high throughout the fall and winter, which contributed to higher energy prices later in the year. The most significant congestion occurred between the Minnesota Hub and WUMS. On average, WUMS prices exceeded prices in Minnesota during peak hours by an average of $13 per MWh. This congestion is consistent with historical patterns and is generally due to the relatively heavy reliance of the WUMS area on imports and the limited capability of the transmission interfaces into the area.

One of the substantial advantages of the new LMP markets is that they provide transparent signals regarding the prevailing market conditions, even when the conditions are abnormal. For example, the congestion that typically occurs from Minnesota to WUMS reversed directions in December and the Minnesota Hub prices substantially exceeded price levels in adjacent areas. This was caused by ice storms in the first week of December and significant planned outages of transmission in Iowa and generation in Minnesota.

Figure 15 shows the same analysis as the prior figure, but it shows the off-peak hours rather than the on-peak hours.

Figure 15: Day-Ahead Hub Prices and Load -- Off-Peak Hours



Like in the peak hours, the figure shows substantial congestion between Minnesota and WUMS during the off-peak hours. This congestion was the most substantial from July to October with the Minnesota Hub prices averaging close to zero in the off-peak hours. These very low prices in Minnesota were caused by frequent congestion related price spikes that occurred in the real-time market and resulted in negative prices in Minnesota. To arbitrage the price levels in the day-ahead and real-time markets, participants bid the day-ahead prices in the overnight hours down to close to zero in a substantial portion of the year. The congestion in the off-peak hours into WUMS was due to a limited ability to reduce flows on the critical lines into WUMS by: a) reducing baseload generation levels in Minnesota, b) reducing power scheduled via DC lines from North Dakota, and c) reducing imports from Canada.

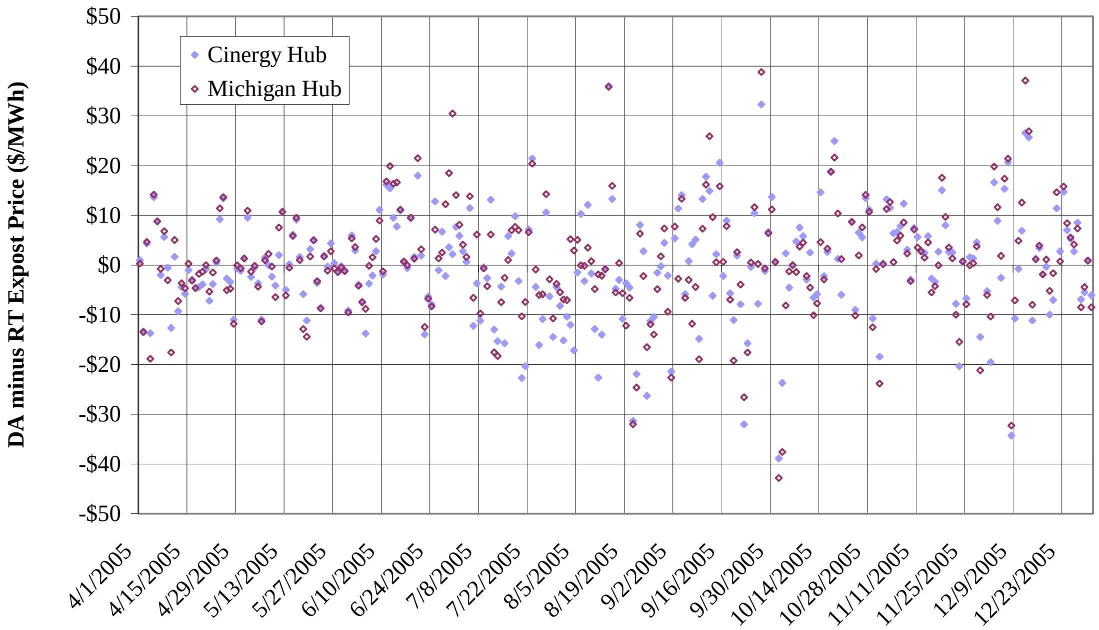
The figure also shows that the generation and transmission outages discussed above contributed to off-peak price increases in the Minnesota and WUMS areas in the beginning of December. Off-peak prices also show the impacts of rising fuel prices (primarily coal). The average price rose from $25 per MWh in the second quarter (April – June) to $36 per MWh in the fourth quarter.

2. Day-Ahead and Real-Time Price Convergence

Our next analysis examines convergence of day-ahead and real-time energy prices. The degree to which day-ahead and real-time prices converge is important because convergence is indicative of a well-functioning day-ahead market. The day-ahead market governs most of the energy settlements and generator commitments in the Midwest ISO region. Hence, good convergence of day-ahead and real-time prices contributes to efficient day-ahead commitments that reflect actual real-time operating needs. Because most wholesale energy that is bought or sold through the Midwest ISO markets is settled through the day-ahead market, efficient outcomes in the day-ahead market are important. 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 FTRs are properly valued and, consequently, markets for these rights operate efficiently, as explained more in subsequent sections.

In general, good convergence is achieved when participants make price-sensitive bids and offers in the day-ahead market – including active virtual supply and demand participation in the day-ahead market. To show the differences between day-ahead and real-time prices, Figure 16 and Figure 17 show the average daily day-ahead to real-time price differences (day-ahead minus real-time prices) at four Midwest hubs. Figure 16 shows the convergence for the Cinergy and Michigan hubs.

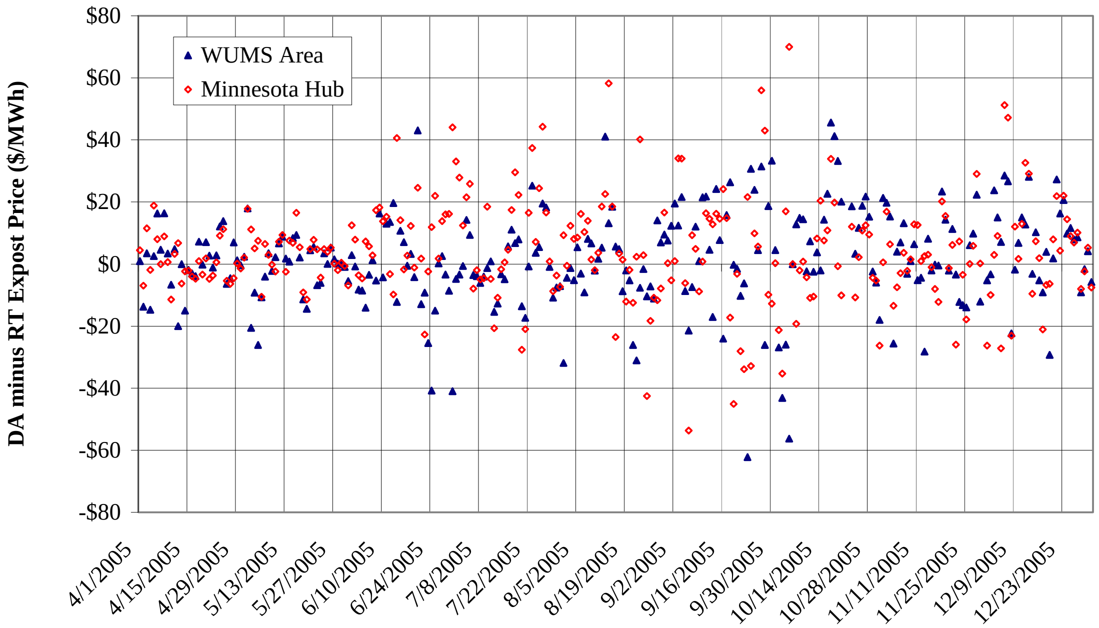
Figure 16: Average Daily Day-Ahead and Real-Time Price Differences Cinergy Hub and Michigan Hub



The average daily differences generally range from $40 and -$40 per MWh. However, the average differences are very small -$0.23 per MWh for Cinergy and $0.53 per MWh for Michigan (neither of which is statistically different from zero given the standard deviation of the data). The Cinergy Hub prices in the day ahead were on average below the real-time prices by nearly $4 per MWh during the summer months of July and August. The Michigan day-ahead prices were also less than real-time by approximately $1.50 per MWh throughout the summer.

Figure 17 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 17: Average Daily Day-Ahead and Real-Time Price Differences Minnesota Hub and WUMS Area

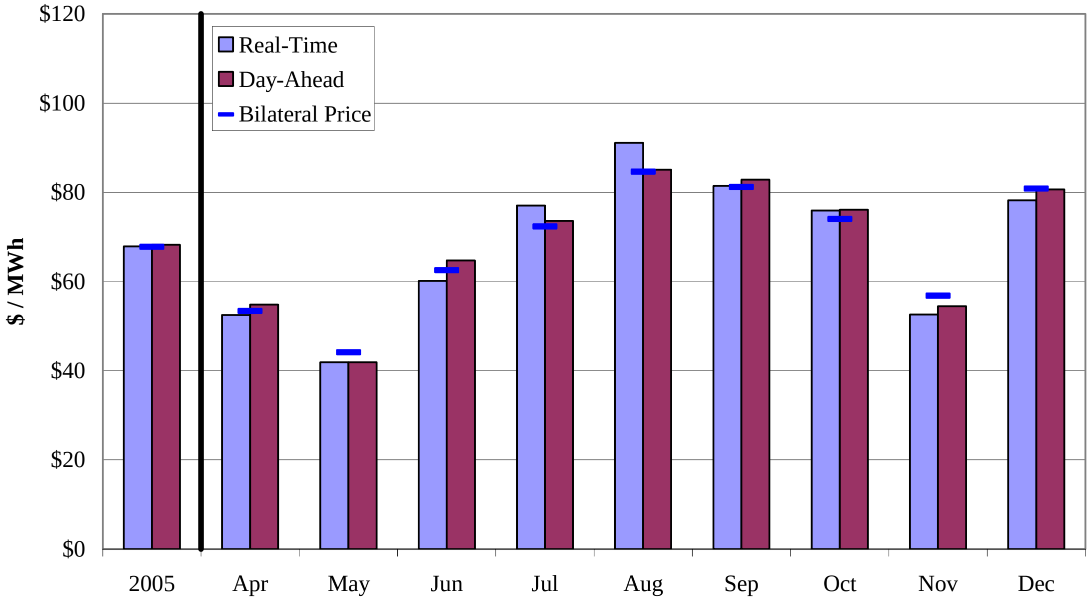


The prices for the Minnesota Hub and WUMS area are frequently affected by the congestion, which causes them to be more volatile that prices elsewhere. For the year, the average daily price differences are larger in these areas -- $4.25 per MWh in Minnesota and $1.57 per MWh in WUMS. The standard deviations are also larger due to the effects of congestion -- $16.50 per MWh and $15.26 per MWh for the Minnesota Hub and WUMS area, respectively.

Although these differences can be relatively large on a hourly or daily basis, convergence should be evaluated over longer timeframes. Participants' bids and offers should reflect their expectations of market conditions the following day. However, a variety of random factors can cause the real-time prices to be significantly higher or lower than expected. Therefore, while a well-performing market will not cause prices to converge on a daily basis, it should cause to converge well on a monthly or annual basis.

To evaluate convergence over the longer-term, Figure 18 shows the convergence of prices on a monthly and annual basis at the Cinergy hub.

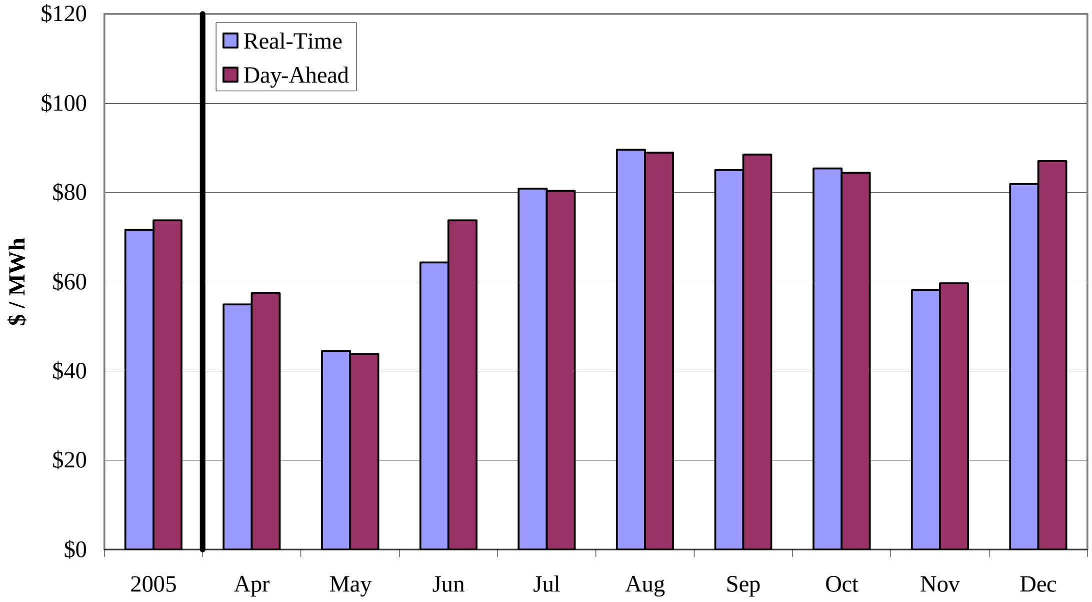
Figure 18: Day-Ahead and Real-Time Prices
Cinergy Hub - Peak Hours



The Cinergy Hub is the most liquid trading point for forward contracting in the Midwest ISO region. Hence, bilateral contract prices are available for this hub and the monthly average bilateral prices are included in the figure. Over the whole nine-month period, the average day-ahead, real-time, and bilateral prices were nearly identical. These results indicate that convergence has been relatively good during the initial operation of the Midwest ISO energy markets. The average price difference between the day-ahead and bilateral market for 2005 was 0.7 percent, which is extremely good convergence. The figure shows that convergence was also relatively good on a monthly basis. The average monthly difference between day-ahead and bilateral contract prices was less than 5 percent in every month.

Likewise, the convergence between day-ahead and real-time markets was relatively good on a monthly basis. The largest differences occurred in the peak months of July and August when real-time prices were nearly $5 per MWh higher than the day-ahead and bilateral prices on average. Given the volatility of the real-time market, these differences during the summer months do not raise significant concerns. Figure 19 shows the same analysis for the Michigan hub. This figure does not show bilateral prices because the bilateral market is not active in this area as it is at the Cinergy hub.

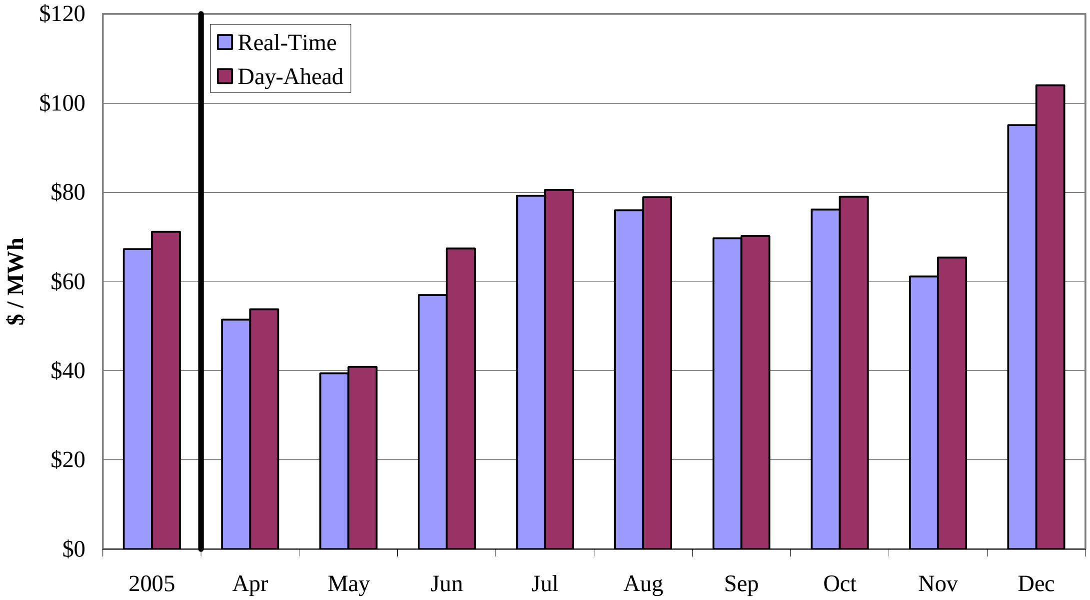
Figure 19: Day-Ahead and Real-Time Prices
Michigan Hub - Peak Hours



The real-time peak prices at Michigan hub on average were $2.14 per MWh less than day-ahead. This was due in part to a $9 per MWh difference in June. This monthly difference was largely caused by a period of extreme high load at the end of June that resulted in congestion into Michigan and by high real-time prices that were not fully reflected in the in the day-ahead market.

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 20 shows the analysis for the Minnesota hub, which is on the unconstrained side of the Minnesota-WUMS interface. Price convergence in Minnesota is likely to be more difficult to achieve because congestion into WUMS causes the Minnesota hub prices to be much more volatile than prices elsewhere in the Midwest ISO region.

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



The prices at the Minnesota hub in the day-ahead were on average above the real-time prices in every month. The largest difference occurred in June when day-ahead prices were higher by more than $9 per MWh. Negative price spikes that occurred during periods of severe congestion contributed to the lower real-time prices. After June, participants more effectively used virtual transactions and price-sensitive load bids to arbitrage day-ahead and real-time prices (i.e., to cause the day-ahead prices to reflect an expectation of price spikes in the real-time market).

The final figure in this series is Figure 21, which shows the same analysis for WUMS. The WUMS area is on the constrained side of the Minnesota-WUMS interface.

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

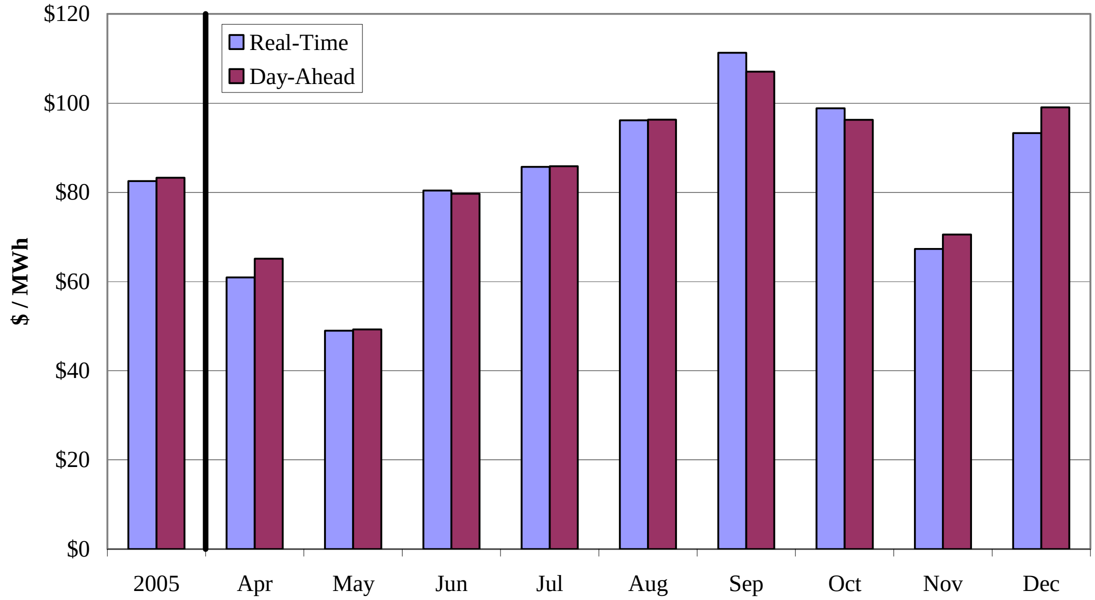


Figure 21 shows that average prices for the year in the day-ahead and real-time markets were very close in magnitude, with the day-ahead prices slightly exceeding the real-time prices. However, real-time prices were higher in the highest-priced months of September and October. Prices were highest and the divergence was the largest during these months because outages and high natural gas prices led to relatively severe congestion in the real-time market.

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.

The table shows various statistics, including the average day-ahead and real-time prices from April to December 2005, the difference in the annual average prices, and the average of the hourly absolute value of the price difference. For each market, we show these pricing statistics for several sub-regions. Five of these sub-regions are particularly affected by congestion: New York City, Connecticut, New Jersey, WUMS, and Minnesota .

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	$50.88	$49.30	$1.54	$13.89
Michigan Hub	$54.18	$52.67	$1.46	$14.99
Minnesota Hub	$46.68	$43.49	$3.02	$19.93
WUMS Area	$62.48	$60.10	$2.38	$20.86
New England ISO:				
Connecticut	$83.16	$80.16	$2.99	$14.84
Maine	$70.83	$70.38	$0.45	$11.59
New England Hub	$78.55	$76.65	$1.90	$12.99
New York ISO:				
Zone A (West)	$66.87	$65.26	$1.61	$15.64
Zone G (Hudson Valley)	$82.54	$82.90	-$0.36	$20.41
Zone J (New York City)	$98.91	$103.82	-$4.90	$25.49
PJM:				
AEP Gen Hub	$46.06	$45.21	$0.85	$11.89
Chicago Hub	$46.93	$46.47	$0.46	$11.76
New Jersey Hub	$67.73	$68.20	-$0.47	$19.06
Western Hub	$60.52	$61.09	-$0.57	$16.20

These results indicate that the convergence between the day-ahead and real-time markets in the Midwest ISO in its initial year of operation was comparable to other established LMP markets. The average price differences in each of the non-congested areas are relatively small (less than $2.00 per MWh). Prices in constrained locations exhibit larger average differences, ranging from $2 to $5 per MWh. This is not unusual because prices are more volatile and more difficult to arbitrage in the congested areas.

The average absolute differences (the average size of the hourly differences, regardless of which price is higher) were generally consistent across each of the markets, ranging from $11 to $15 per MWh. These values were consistently higher in congested areas, ranging from $19 to $26 per MWh in the congested areas because prices are more volatile in these areas. In the two congested areas in the Midwest ISO region, the average absolute price difference were $20 and $21 per MWh.

Overall, these results indicate that the price convergence in the Midwest ISO markets has been good in its first 9 months of market operation. This is likely due in large part to the rapid growth in virtual trading volumes, as discussed below.

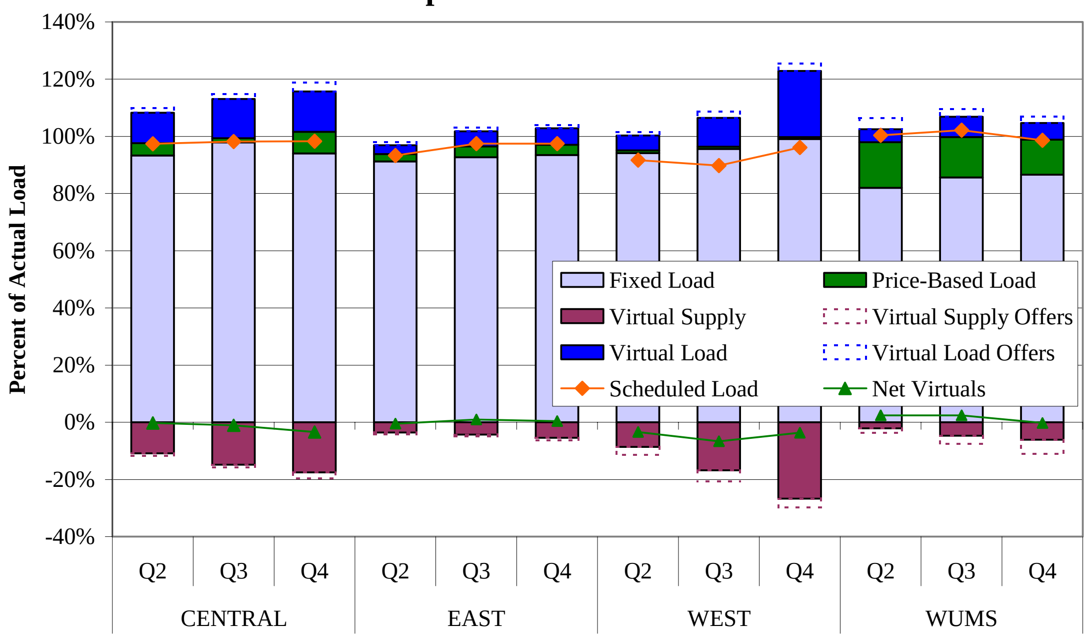
3. Day-Ahead Load Scheduling and Virtual trading

Our next analysis addresses day-ahead load scheduling and virtual trading. These aspects of the market can have important impacts on market efficiency. They contribute to efficient results in the day-ahead market and good price convergence.

Day-ahead load scheduling is the demand side of the day-ahead market. Day-ahead load schedule can be either price-sensitive or fixed. A price-sensitive load schedule is a load bid that cleared in the day-ahead market. The 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 22 shows each of the components of the schedules that have cleared 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.

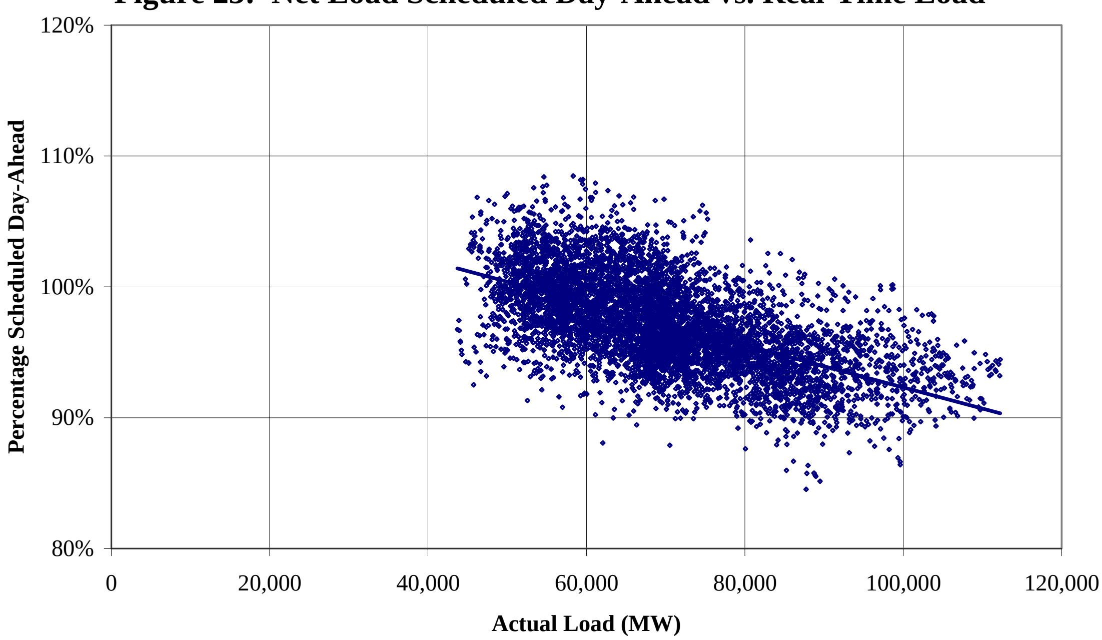
Figure 22: Composition of Day-Ahead Load Scheduling as a Proportion of Actual Load



This figure shows that the vast majority of the 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. Hence, one can see from these results that almost all of the price-sensitivity on the demand side in the day-ahead market is provided by the virtual traders rather than the physical loads. This underscores the importance of virtual trading in ensuring efficient day-ahead market outcomes. The figure shows that the virtual supply and demand cleared in the day-ahead market was the highest in the fourth quarter, particularly in the West where prices have been volatile due to congestion. We discuss virtual trading patterns in more detail below.

Finally, the figure shows that the net scheduled load (total load net of virtual supply) is slightly lower than 100 percent in all quarters and locations except in WUMS. Net load is lowest in Minnesota and highest in WUMS. This is consistent with participants' attempt to arbitrage day-ahead and real-time price differences associated with transmission capability into WUMS that is lower on average in the real-time market than the day-ahead. This is generally the result of outages and other factors that are not foreseen in the day-ahead, or loop-flows caused by activity outside the Midwest ISO region that are not fully reflected in the day-ahead market. To examine the net scheduled load patterns on a market-wide basis, Figure 23 shows the percentage of real-time load scheduled in the day-ahead market relative to the actual real-time load.

Figure 23: Net Load Scheduled Day-Ahead vs. Real-Time Load



This figure shows that net scheduled load in the day-ahead market is slightly less than 100 percent on average. This slight under-scheduling of load is consistent with other markets and can result in reliance on peaking resources and supplemental commitments by the Midwest ISO to satisfy real-time needs. Hence, it is important for peaking resources to set prices when needed to provide the economic incentive for load to be fully scheduled in the day-ahead market.

The figure also indicates that the percentage of load scheduled generally decreases as the load increases. This pattern is likely caused, in part, by the increased reliance on peaking resources in the highest load periods. Such resources set prices in the day-ahead market when they are scheduled in that market. However, peaking resources frequently do not set prices in the real-time market due to their inherent operational inflexibility. This creates the economic incentive for participants to reduce their net scheduled load in the day-ahead market under the highest load conditions when peaking resources are needed the most.

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 a virtual seller offers a MW of power for $50 in the day-ahead market, the seller must then purchase $50 in the real time to cover its trade. Accordingly, if the virtual trader expects real-time prices to be lower than day-ahead prices, the seller takes virtual supply positions and, if the expectation is correct, then the virtual seller makes a margin on each MW sold day-ahead. Likewise, if a virtual trader expects real-time prices to be higher than 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 to real-time prices, contributing to increased efficiency in the day-ahead market.

Figure 24 shows the hourly average virtual load bids and supply offers in the peak hours for each day from April through December of 2005, 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 the dashed areas on the top of the bars for each day.

Figure 24: Virtual Load and Supply in the Day-Ahead Market 2005: Peak Hours

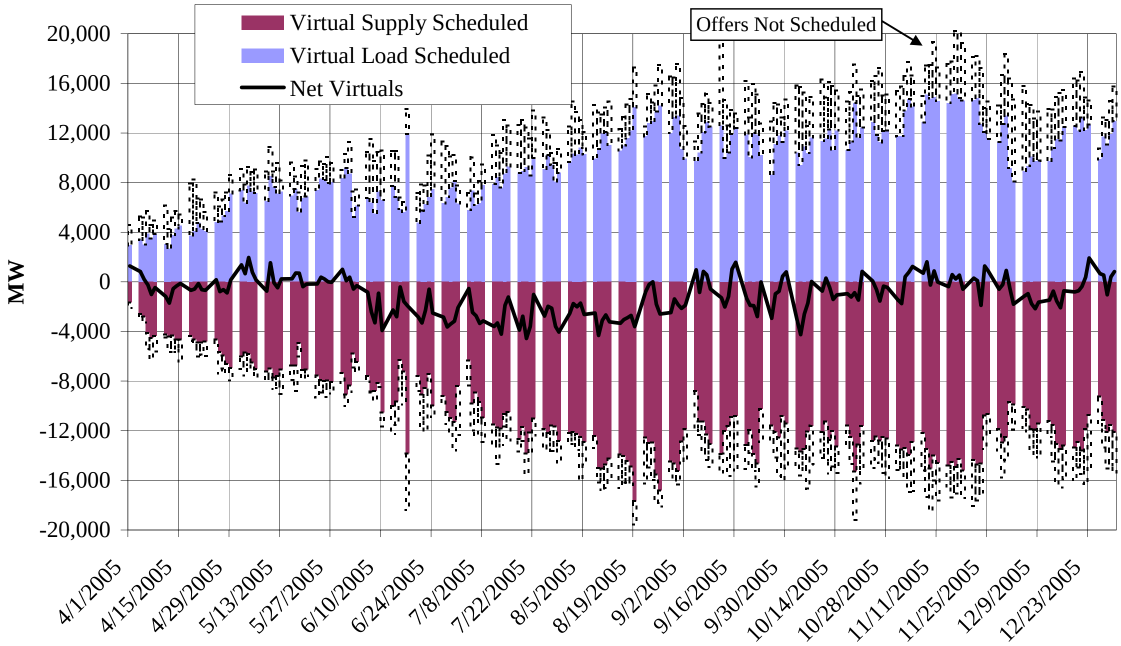
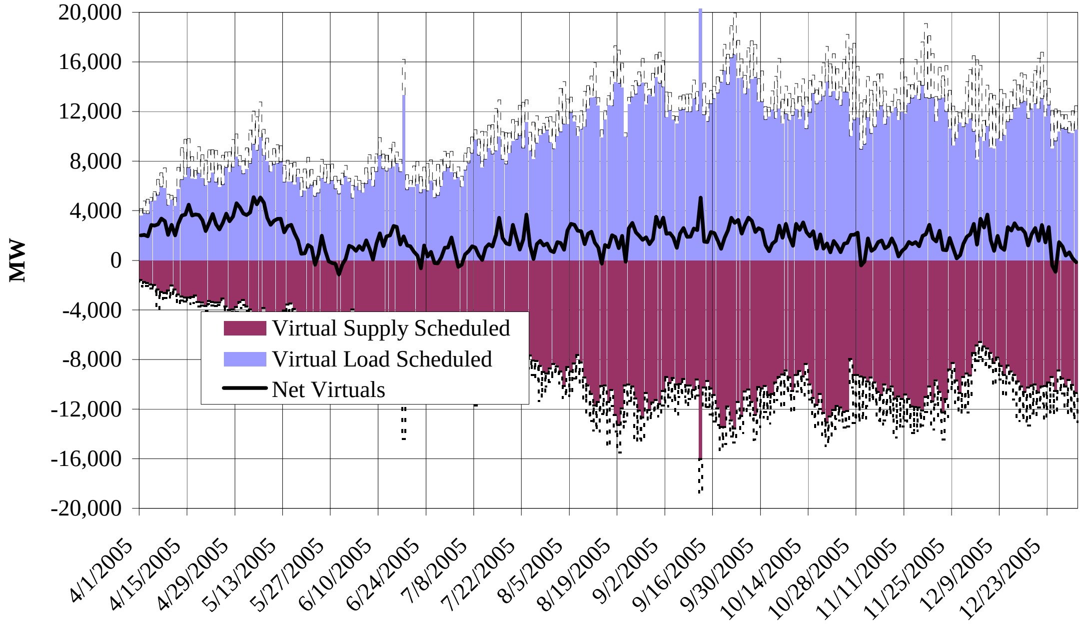


Figure 24 shows that virtual trading volumes have grown rapidly over the initial 9 months of market operation. Virtual load bids and supply offers have both more than tripled in volume since the market was introduced. The rapid increase in the liquidity of the virtual trading contributes to efficient day-ahead market outcomes. These volumes of virtual transactions, which already surpass other RTO markets, is likely partially due to the low level of costs allocated to these transactions. In particular, "uplift" costs are disproportionately allocated to real-time settlements associated with virtual trades in some markets, which is a practice that discourages such virtual transactions.

Figure 25 shows the same analysis as the prior figure, but for off-peak hours instead of peak hours. The results affirm the findings for the peak hours that virtual trading has increased substantially since market inception.

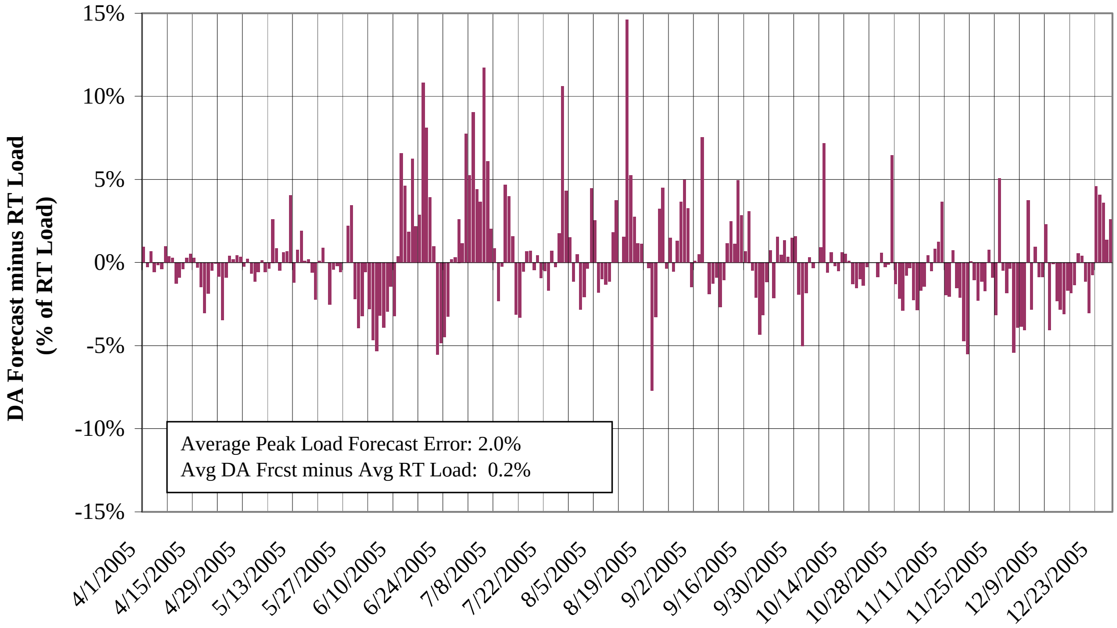
Figure 25: Virtual Load and Supply in the Day-Ahead Market 2005: Off-Peak Hours



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 additional resources that are unnecessary or not to commit resources that are needed, 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 26 shows the percentage difference between the day-ahead forecasted load and real-time actual load for the peak hour of each day for April and December 2005.

Figure 26: Daily Day-Ahead Forecast Error in Peak Hour
April to December 2005



This figure shows the average peak load forecast error was 2 percent on average (forecast error is the magnitude of the error, regardless of direction). However, on certain days the error exceeded 10 percent. In general, the higher errors occurred in the summer when uncertainty regarding weather-sensitive load is the highest.

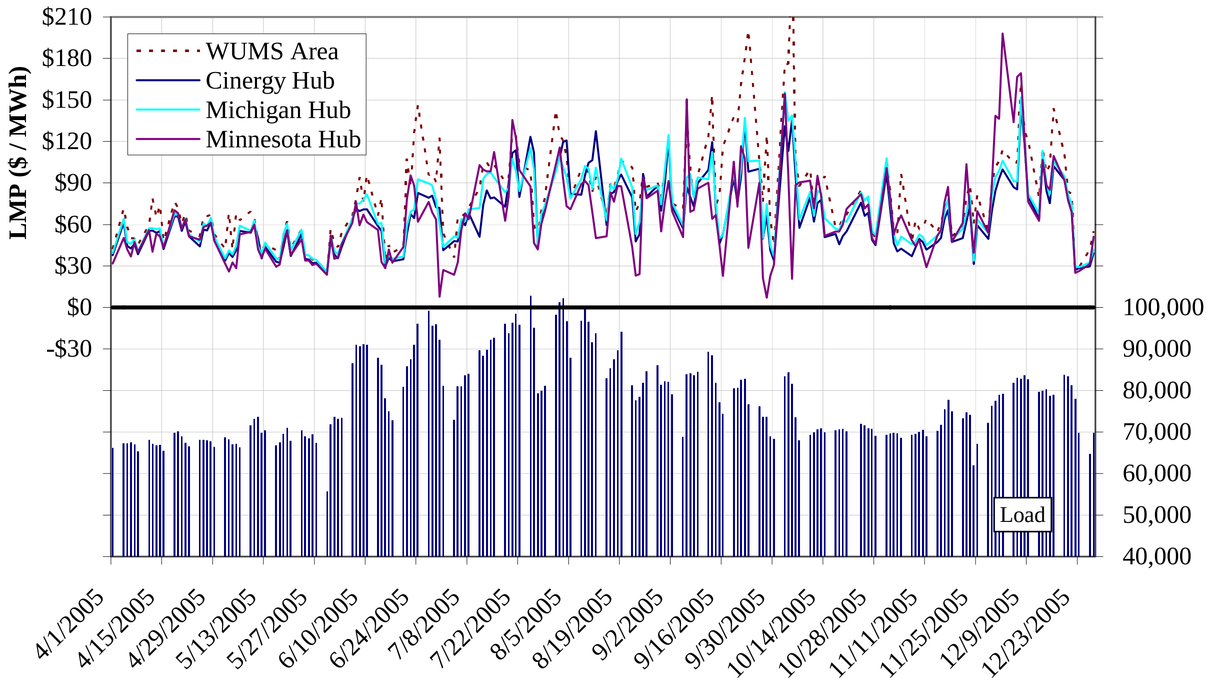
Over all of the days' hours, the average difference between the day-ahead forecast and real-time load was only 0.2 percent – indicating that the forecast is not systematically biased. These results indicate that with the exception of some isolated days during 2005, the day-ahead forecasting process has been relatively good. In fact, these levels of forecast error are superior to most of the other RTOs. However, the figure does show that the load tended to be over-forecasted in the summer and under-forecasted in the fall. The Midwest ISO should investigate the nature of these seasonal errors and determine whether any changes can be made to address them.

B. Real-Time Market Outcomes

In this subsection, we evaluate the real-time market outcomes. The real-time market is important because it 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 forward market prices. 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.

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 27.

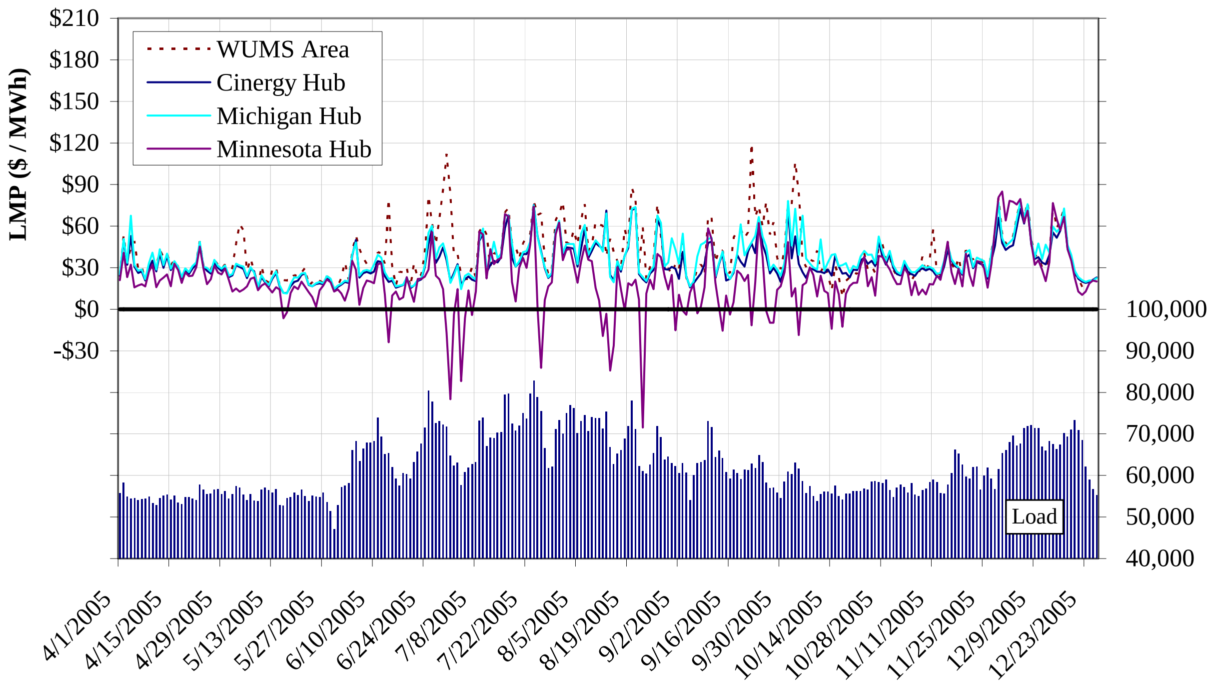
Figure 27: Real-Time Hub Prices and Load
Peak Hours



The figure shows a general correlation between peak load and peak hour prices. Although it is difficult to discern from this figure, natural gas prices also contribute to higher real-time prices in the fall and winter periods.

Figure 27 also shows some notable price separation between the four locations due to transmission congestion. As in the day-ahead market, the most substantial congestion occurs between Minnesota and WUMS. The average annual price difference between these two locations during peak load hours is well over $15 per MWh with a maximum hourly price difference of over $230 per MWh. Price differences in the real-time market are greater due in part to reduced bid flexibility and ramp limits that tend to exacerbate congestion. The figure also shows that in December there was a notable reversal of the congestion in the west sub-region of the Midwest ISO marked by a spike in Minnesota Hub prices. This congestion was due to ice storms in the first week of December and significant planned outages of transmission in Iowa and generation in Minnesota. Figure 28 shows the same analysis for the off-peak hours.

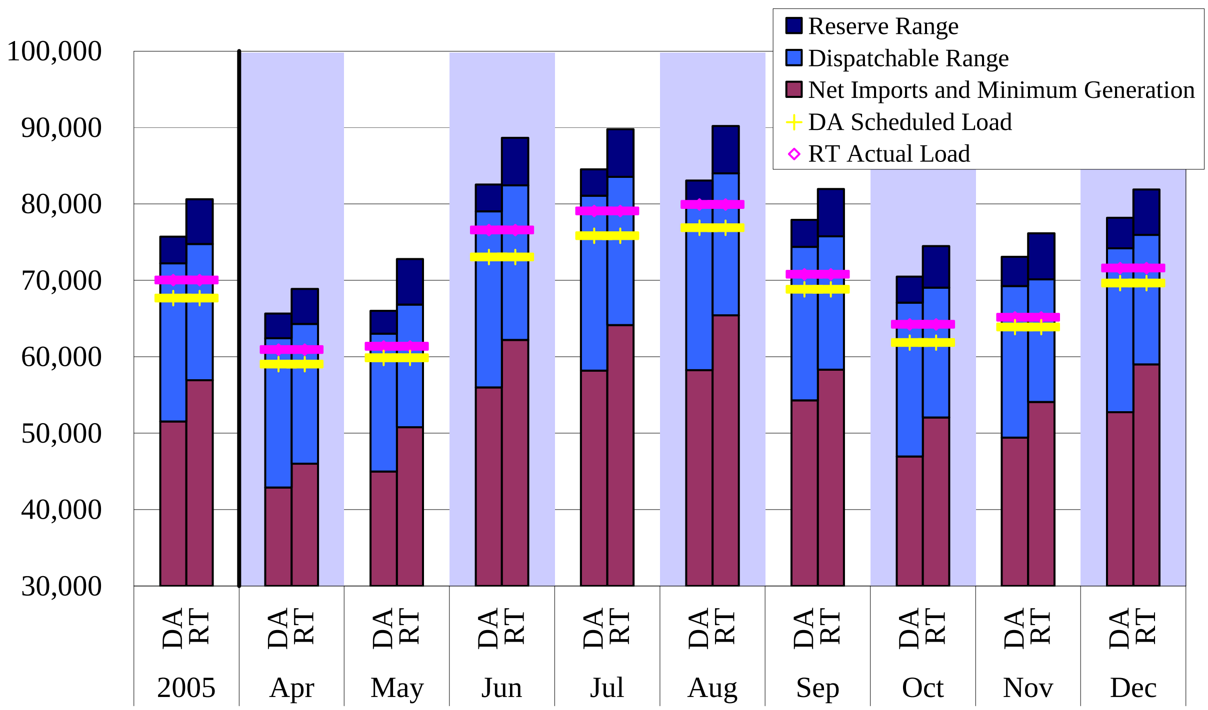
Figure 28: Real-Time Hub Prices and Load
Off-Peak Hours



The prices shown in this figure are substantially lower as one would expect because relatively low-cost baseload coal resources set the energy price in most off-peak hours. This figure also shows that the congestion between Minnesota and WUMS is frequently substantial in the off-peak hours. This congestion frequently caused prices in overnight hours to be sharply negative, indicating that the Midwest ISO would *pay* a generator to produce less output. As we will discuss later in this report, these patterns are generally caused by reduced generator flexibility and other factors that limit the Midwest ISO's ability to redispatch the system to manage the congestion.

Our next analysis in Figure 29 shows a comparison of the actual real-time and day-ahead scheduled generation, which provides an initial review of the overall flexibility of the generation in the Midwest ISO region.

Figure 29: Day-Ahead and Real-Time Generation
2005: All Hours



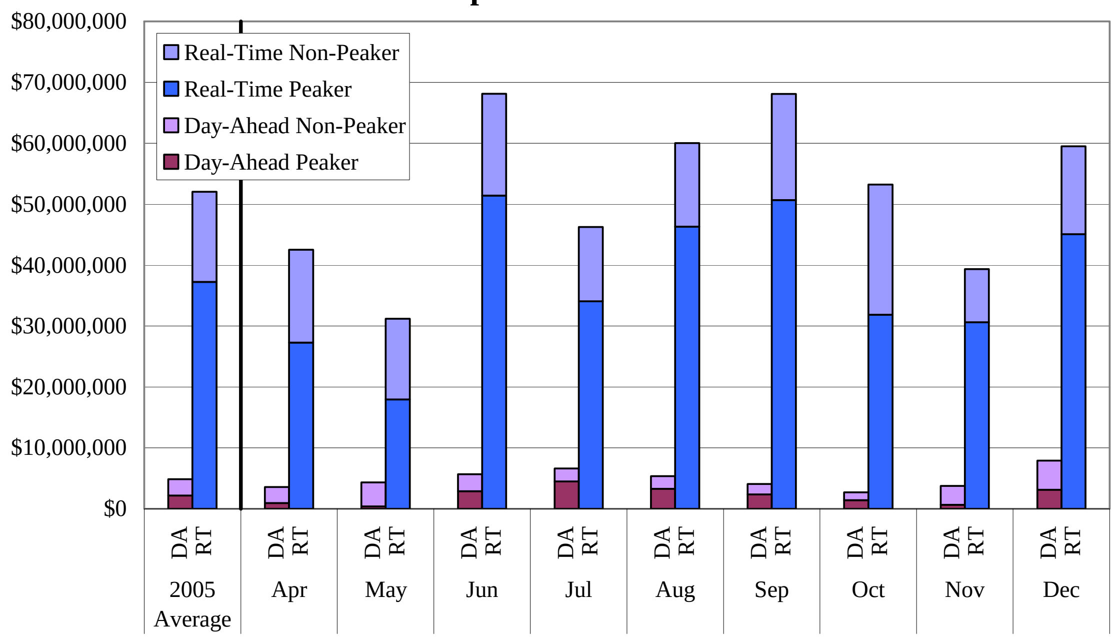
The figure shows that generation levels are generally higher in the real-time market. Participants that self-schedule resources after the day-ahead market contribute to this increase. Additionally, the Midwest ISO must sometimes commit resources after the day-ahead market when: load is higher than expected, load is under-scheduled in the day-ahead markets, or net virtual supply is scheduled in the day-ahead that must be replaced by physical generation before real time. Nonetheless, most generation is scheduled through the day-ahead market – on average, 97 percent of real-time generation is scheduled in the day-ahead market. The largest increase in generation from day-ahead to real-time occurred in the summer months when under-scheduling of the load was the largest. Much of this increase in real-time generation was associated with the dispatch of peaking resources.

Figure 29 also shows that dispatch flexibility is reduced in the real-time market. The dispatch range (EcoMax-EcoMin) as a percentage of total online capacity declines from 30 percent in the day-ahead market to 25 percent in the real-time. These values are substantially lower than the physical flexibility that generating resources could provide. Although it varies substantially by technology type, generators can physically provide a dispatch range of 50 to 60 percent on average. This reduced dispatch flexibility can significantly affect the real-time market by limiting redispatch options needed to manage congestion. This issues is evaluated in detail 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 offered costs. Figure 30 shows monthly RSG payments generated in the day-ahead and real-time markets to peaking units and other units.

Figure 30: Total RSG Distribution by Market
April to December 2005



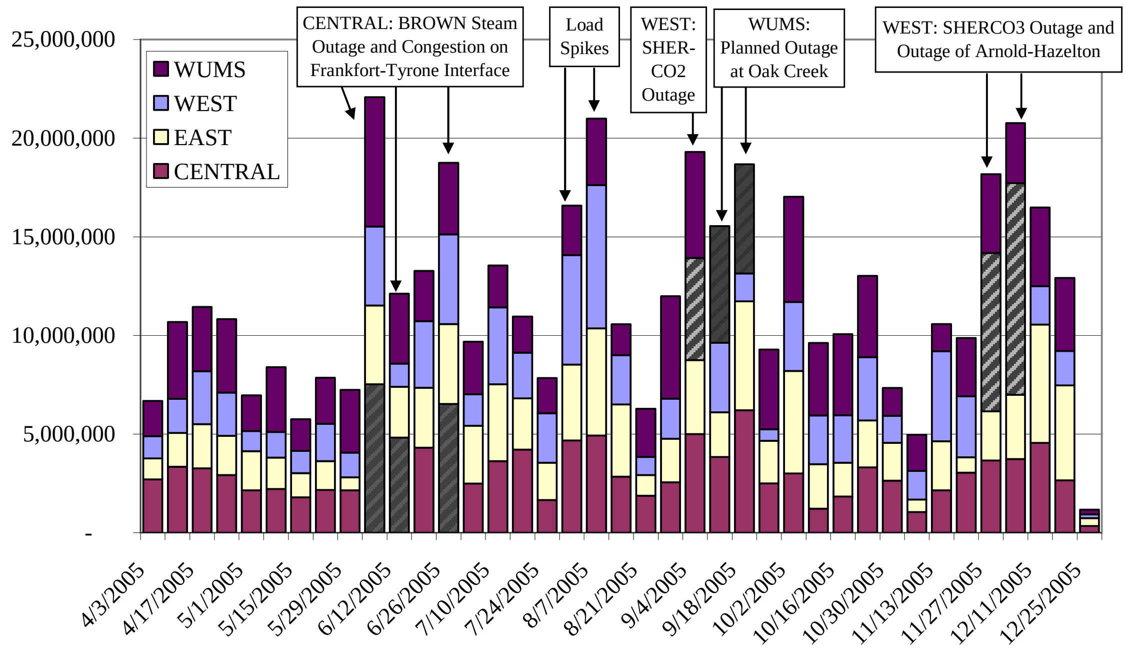
Resources that are not committed in the day-ahead market, but must be started to maintain reliability are likely recipients of RSG payments – this is "real-time" RSG because such units receive their revenue from the real-time market. Because the day-ahead market is a financial market, very little RSG 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 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 30 shows that the vast majority of RSG payments are generated in the real-time market and are payable to peaking resources. RSG payments to peaking units accounted for at least 74 percent of RSG payments in all months except for April (64 percent), May (58 percent) and October (60 percent). This is despite the fact that peaking resources accounted for only 2 percent of the energy generated in the Midwest ISO. This is not surprising because peaking resources are the highest-cost resources and, therefore, earn the least profit in the energy market when they run. 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 a RSG payment will be needed to cover their as-bid costs.

In total, real-time RSG payments made in 2005 exceeded $600 million. The figure shows that RSG payments were generally highest in the highest load months because peaking resources were most heavily relied upon in these periods. RSG payments remained relatively high in the fall due to extremely high natural gas prices and in December they were again relatively high due primarily to transmission and generation outages discussed further below.

To provide an indication of how some specific factors affected RSG costs, Figure 31 shows RSG payments data on a weekly basis and by sub-region. Showing the RSG payments on a weekly and sub-regional basis allows one to more clearly discern some of the key events that contributed to the RSG costs. The cross-hatched areas in each bar are RSG payments that were generated in part due to the system condition described at the top of the bar.

Figure 31: Weekly RSG Distribution by Region



There were two main drivers of RSG payments. The first is the summer peak load conditions. The RSG levels were the highest in the last week of June, mid to late-July, and the first two weeks of August. These were all times when load was particularly high, periodically exceeding 100 GW. Peak load conditions frequently require supplemental commitments to ensure a smooth ramp and adequate reserves throughout the system.

The second driver of RSG payments is transmission congestion and local reliability requirements. Figure 31 shows that substantial episodic increases in RSG were attributable to transmission and generation outages that contributed to significant congestion and local reliability needs. For example, the first highlighted RSG event in June 2005 was associated with the outage of a steam unit in the Central region that caused voltage issues and contributed to congestion of the Frankfort–Tyrone interface. To address these issues, the Midwest ISO had to commit relatively costly peaking resources in that area on a daily basis. Likewise, outages in the West sub-region and in WUMS in September resulted in supplemental commitments in these areas that generated significant RSG payments. The December planned generator outages in

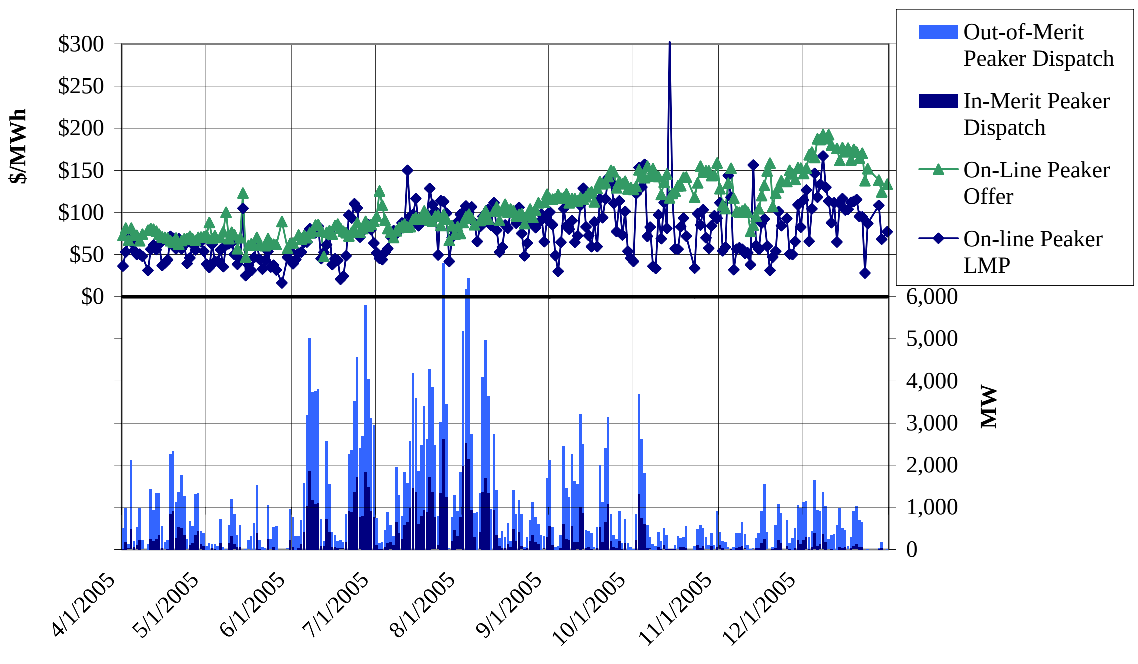
Minnesota, together with a transmission outage of the Arnold-Hazelton line in Iowa, required supplemental commitments in the West that resulted in substantial RSG payments.

In many of these cases, the units that needed to satisfy the reliability need of the Midwest ISO were generally owned by a single supplier. As discussed further in the competitive assessment section of this report, the mitigation measures contained in the Midwest ISO tariff were critical in limiting potential abuses of market power during these periods.

D. Dispatch of Peaking Resources

As discussed above, the dispatch of peaking resources are important because peaking resources are an important determinant of RSG costs and efficient energy price signals. Figure 32 summarizes the dispatch of peaking resources in 2005, 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. It also shows the shares of the peaker output that are in-merit (LMP > peaker offer) and out-of-merit (LMP < peaker offer).

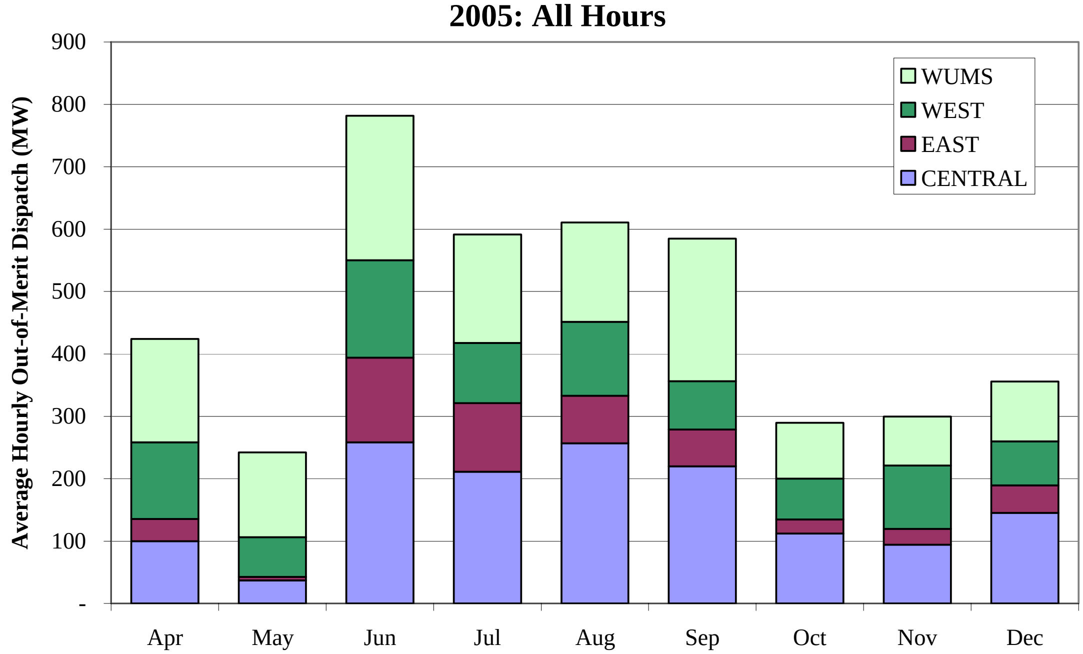
Figure 32: Average Daily Peaker Dispatch and Prices All Hours



On average, 500 MW of peaking resources were dispatched on non-summer days and 1300 MW were dispatched on summer days. Average dispatch of peaking resources was highest on July 25, August 2-3, August 9, and June 27. Load exceeded the forecasted annual peak of 107 GW on each of these days. Average dispatch levels of the peaking resources on these days ranged from 5800 MW to 6800 MW while the maximum dispatch level exceeded 15000 MW.

This figure also shows that a large share of the peaking resources are out-of-merit, indicating that they frequently do not set the energy price when they are dispatched. Larger shares of the peaking resources dispatched during the summer are in-merit because they set prices more frequently during high-load periods. This can be explained by the larger numbers of peaking resources running during these periods that increase the likelihood that at least one of the units will have be dispatched in the flexible range between its Ecomin and Ecomax, making it eligible to set the energy prices. However, in most periods when peaking resources are being utilized, the figure shows that most of these resources are running out-of-merit. 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 33 shows the hourly average of these quantities by region and month.

Figure 33: Average Hourly Out-of-Merit Dispatch of Peaking Resources 2005: 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. The figure shows out-of-merit quantities were highest during the summer when the load and the need for peaking resources were the highest. The figure also shows that the peak out-of-merit quantities occurred in June, which was caused by high load and voltage problems in Kentucky that required frequent dispatch of peaking resources.

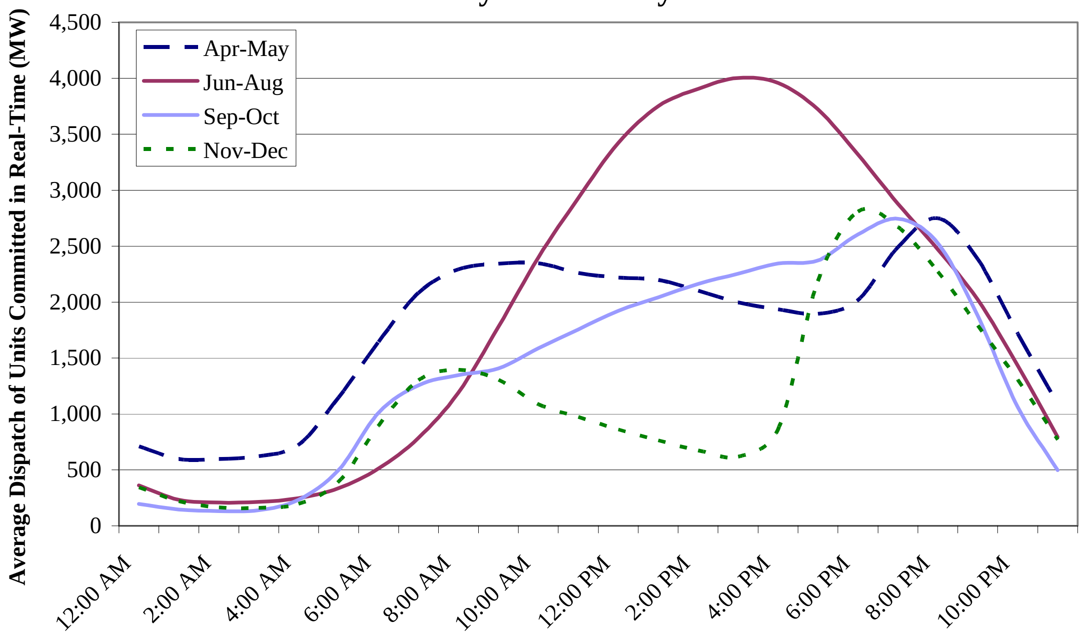
The figure also shows that the out-of-merit dispatch of peaking resources was relatively high in April. These levels were higher than expected given that loads are relatively moderate in April. In evaluating the out-of-merit dispatch of peaking resources, it is important to recognize that starting more 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 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 Forward Reliability Assessment Commitment (FRAC), 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 within the day and when peaking resources can be decommitted.

These improvements are reflected in the analysis in Figure 34, which shows all commitments after the day-ahead by the Midwest ISO that are eligible for RSG payments. This figure shows the average energy produced by such units by time-of-day in different time periods.

Figure 34: Energy Produced from Units Committed in Real-Time By Hour of Day



The figure indicates that early in the market's operation, units committed in the real-time often began producing energy overnight, prior to the morning ramp, and continued producing energy during the middle of the day. Under similar load conditions in the fall, the Midwest ISO refined its commitment and de-commitment processes to start units later and to decommit them more frequently in the middle of the day when they are not needed to meet the ramp demand of the market. These operational improvements reduced RSG payments. In the summer months, the output of units committed in real time peaks at around 3 pm because many of the real-time commitments are made to meet the peak load that occurs at that time.

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 indicate that 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 decommit turbines based on operating criteria. Allowing a market model to indicate when gas turbines should be committed and decommitted should reduce the out-of-merit dispatch quantities, reduce RSG payments, and improve the ability of peaking resources to set the energy price.

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 may set prices. Hence, the units eligible to set ex post prices can be different than 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 35 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 35: Ex Ante and Ex Post Price Differences
All Hours**

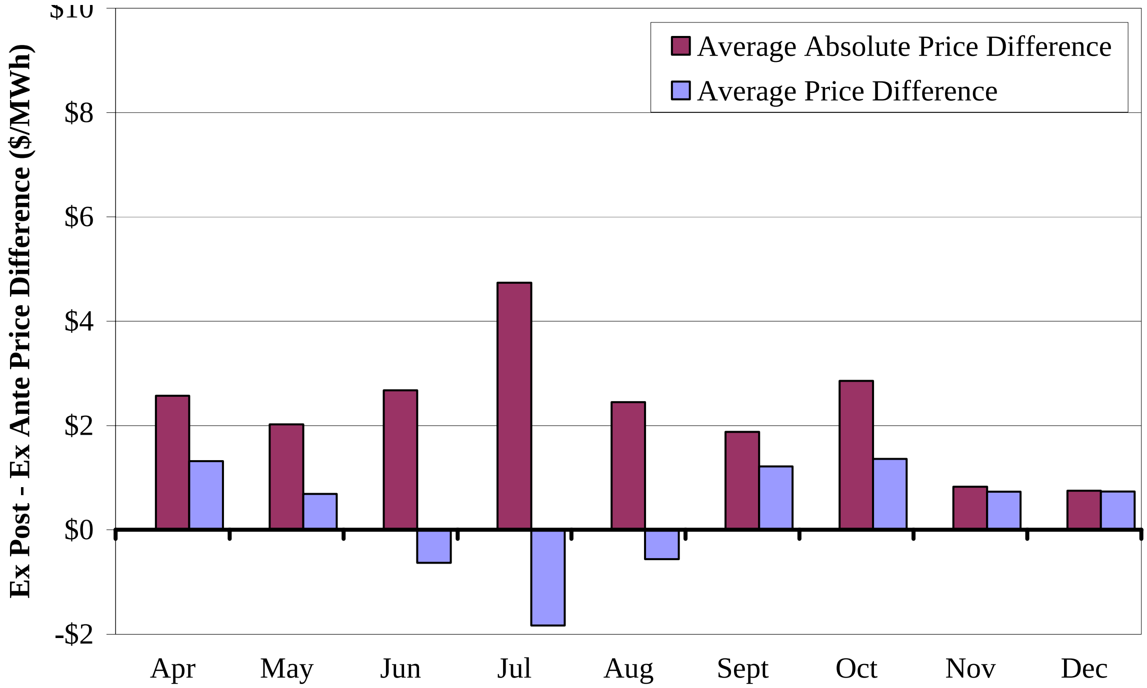
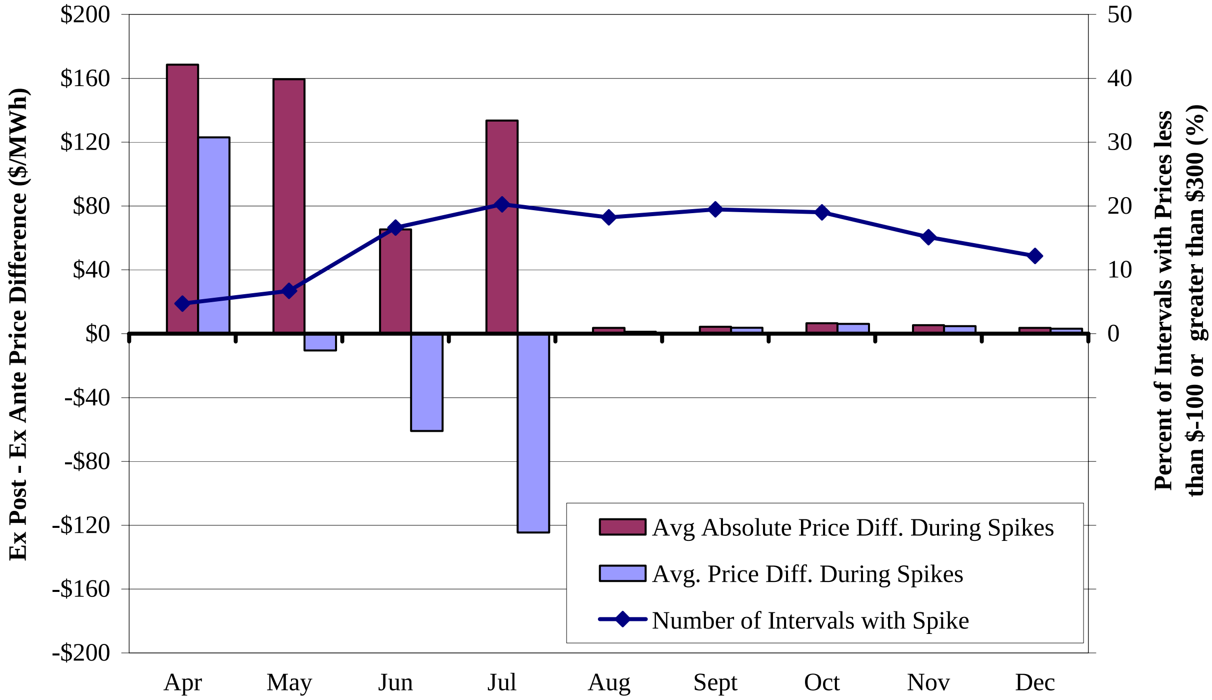


Figure 35 shows the average differences between the five minute ex post and ex-ante prices were relatively small. The typical hourly difference (the average absolute difference) was generally also small, with the exception of July. Although the average differences between ex post and ex-ante pricing have not been large, it is important to evaluate substantial differences during peak demand conditions or periods of extreme congestion. Evaluating consistency during price spikes is important because it is during price spikes that generators may be asked to change output 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 adhering to the Midwest ISO's dispatch instructions.

To evaluate this issue, our analysis in Figure 36 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 36: 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. Modifications were made by the Midwest ISO in early August 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 had prevailed previously.

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 is 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 inaugural year in operation, the Midwest ISO's markets have performed relatively well. However, the lack of real-time ancillary services markets and certain other factors have created room for improvement in the performance of the real-time market. We provide the following recommendations:

- Develop real-time ancillary services markets as soon as practicable. Ancillary services markets that are jointly optimized with the energy markets will allow the market to more efficiently allocate resources. Jointly-optimized ancillary service market will also help set efficient prices in both markets to reflect the economic trade-offs between reserves and energy.

- Complete and implement the full ARC procedures that allow the Midwest ISO operators to activate and dispatch the reserve range on units (output above EcoMax). This process will allow the Midwest ISO to reduce system costs by relying on operating reserves for brief periods rather than committing relatively high-cost units. The ARC is also a means for the market to set prices at $1000 when the system is in shortage (i.e., cannot meet its operating reserve requirements).

- Develop a "look-ahead" capability in the real time that would commit turbines and better manage ramp capability on slow-ramping units. The Midwest ISO has made operational improvements in its commitment of peaking resources, but the commit of these units can be further improved by reliance on an economic model to commit the units. 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 commit them (and decommit them) should generally be an economic decision that could be indicated by a market-based model that looks ahead one to two hours. This change would likely reduce the out-of-merit quantities, reduce RSG payments, and improve the ability of peaking resources to set the energy price.

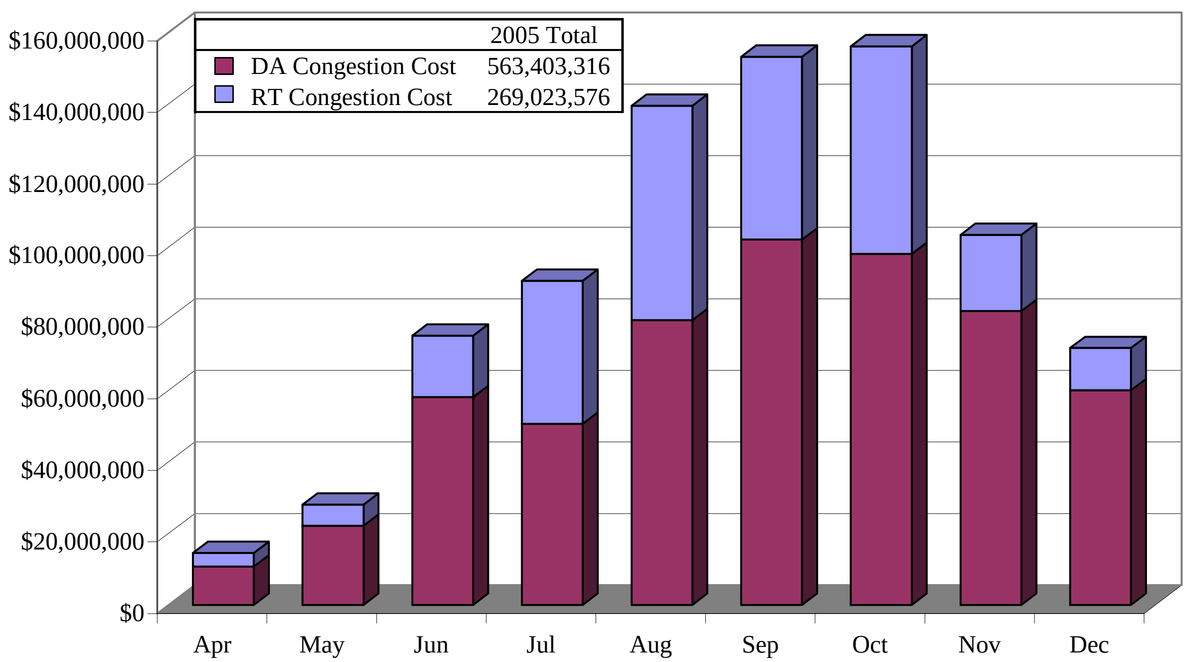
- In the longer-run, develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices. This is a difficult challenge because the market must distinguish between those turbines that would still be needed if they were more flexible versus 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.

V. Transmission Congestion and Financial Transmission Rights

This section summarizes and evaluates the transmission congestion costs in the day-ahead and real-time markets in 2005. 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 re-dispatched 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 37 summarizes the total congestion costs on a monthly basis for 2005.

Figure 37: Total Congestion Costs
April to December 2005



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 times 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).

The total day-ahead congestion costs paid by market participants in 2005 were $563 million and the total real-time congestion costs were $269 million. The congestion costs increased rapidly from the spring to the summer as higher loads and power flows throughout the Midwest resulted in higher congestion. In addition, higher gas prices in the late summer and fall increased the costs of congestion in the second half of the year. In general, higher fuel prices increase the costs of re-dispatching generation to manage congestion.

As discussed more below, a large share of the increase in congestion is due to increased congestion into WUMS and increased congestion on the path to TVA. Real-time congestion costs in 2005 were higher than expected. 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. The issues related to real-time congestion are discussed later in this section.

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 locations defining the right. FTRs allow participants to manage the price risk associated with congestion.

FTRs are created through the annual allocation process, and through the 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 the 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.[4]

[4] An FTR obligation can be in the “wrong” direction (counter flow) and can require a payment from the participant.

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 its obligations to the FTR holders. Figure 38 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 38: Day-Ahead Congestion and Payments to FTR Holders

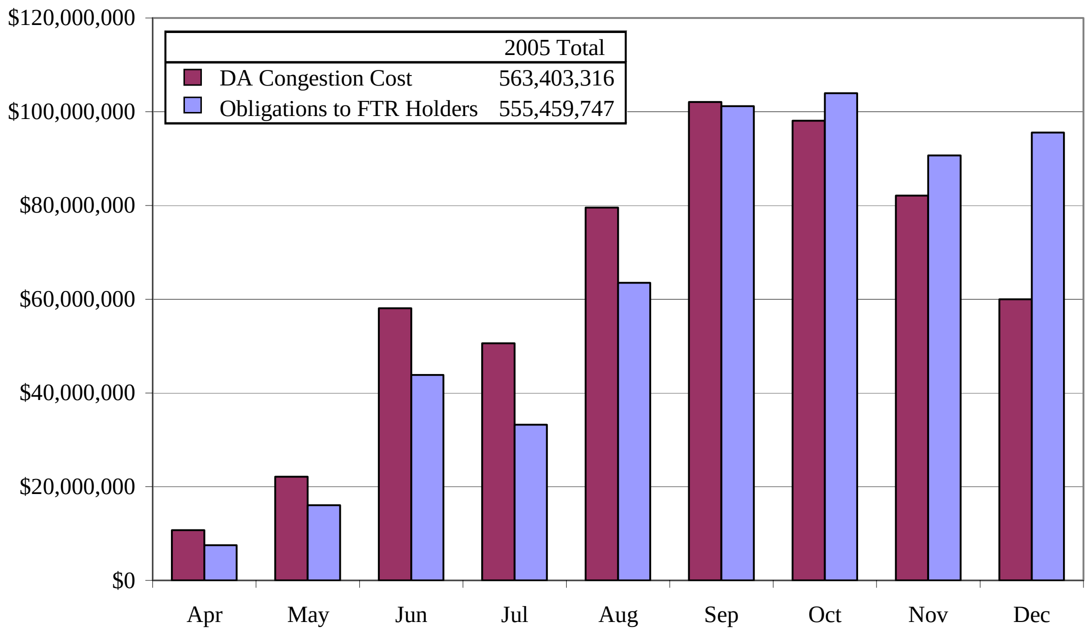


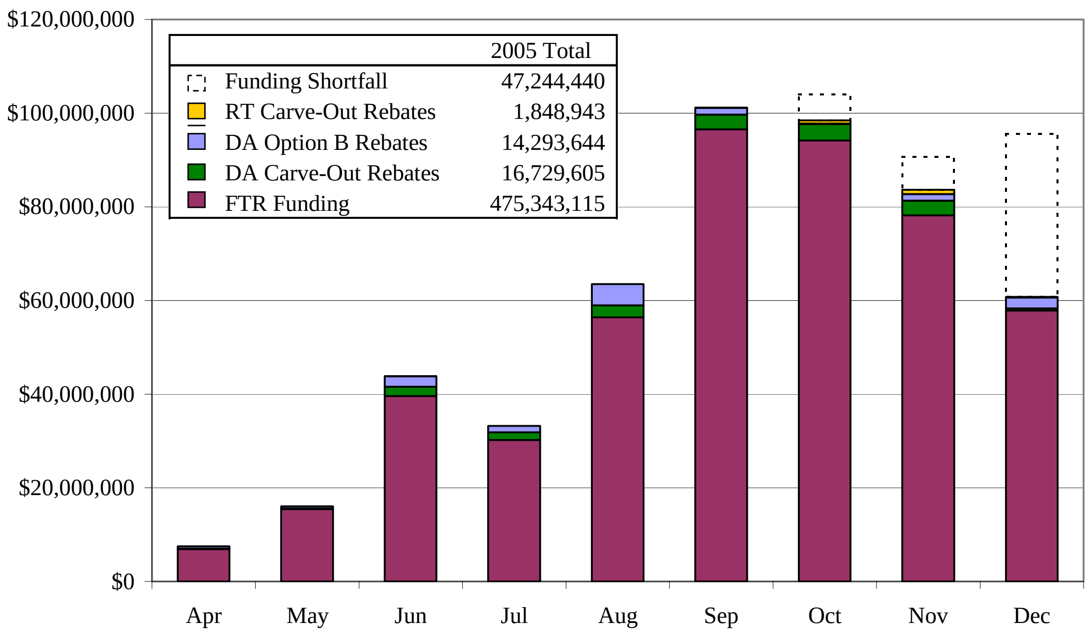
Figure 38 shows that total day-ahead congestion collections exceeded FTR obligations for the year. It also shows that there was a considerable surplus in the first six months of the markets operation. However, there was a monthly shortfall in the last 3 months of the year. A number of factors contributed to the shortfall in the last 3 months, including:

- 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 be an FTR revenue shortfall.

In the Midwest ISO region, other types of transmission rights were created for the purpose of protecting entities that have pre-existing contracts and 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 39 shows the monthly payments and obligations to FTR holders, including payments to FTR Option B and Carve-Out FTRs.

Figure 39: Payments to FTR Holders
2005: All Hours



Shortfalls occurred in the last 3 months of 2005, totaling $47 million. However, this shortfall was covered by surpluses in other months so overall FTR were fully funded on an annual basis.

After all FTR obligations were met, the Midwest ISO had $52 million of surplus congestion collections (FTR funding) that was distributed to firm transmission customers.

The figure shows that the vast majority of the payments were made to FTR holders. More than 95 percent of all payments were made to FTR holders, versus the other types of transmission rights that were made available to participants with grandfathered agreements. This is good because the other types of rights distort participants' operating incentives and can ultimately lead to a less efficient commitment and dispatch.

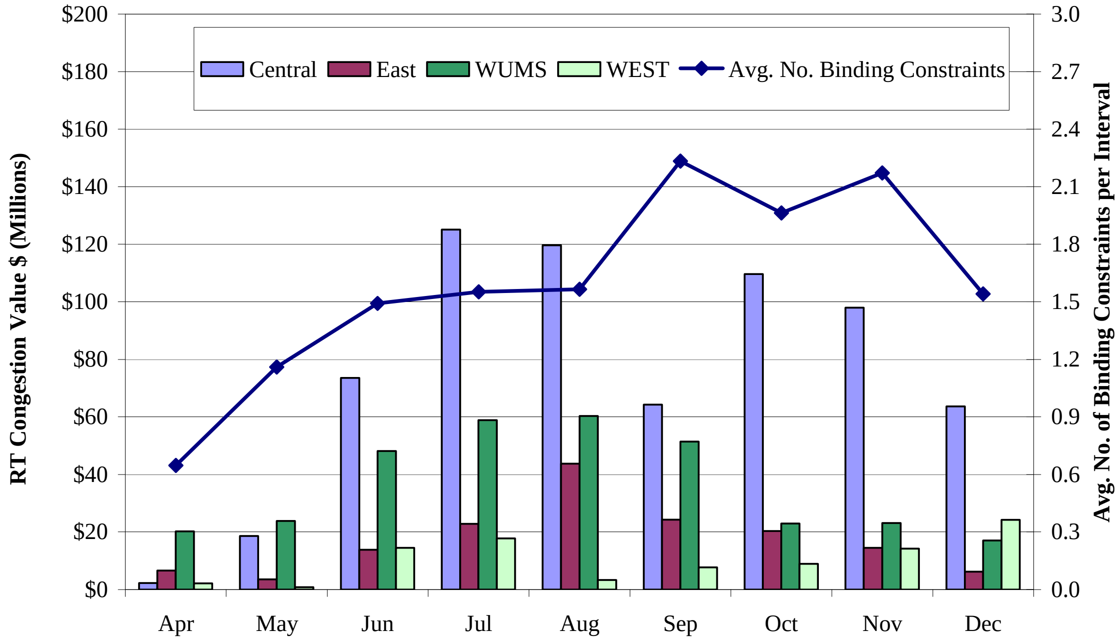
As noted above, the primary causes of the shortfall were differences in the transmission topology and loop flow assumptions in the day-ahead market and the FTR model. In particular, the ISO improved its assumptions regarding loop flows in the day-ahead market, which reduced the congestion revenues collected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

B. Real-Time Congestion

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 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 settlements.

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 40 shows the value of real-time congestion for all the binding real-time constraints in 2005 by region.

Figure 40: Value of Real-Time Congestion by Coordination Region April - December 2005



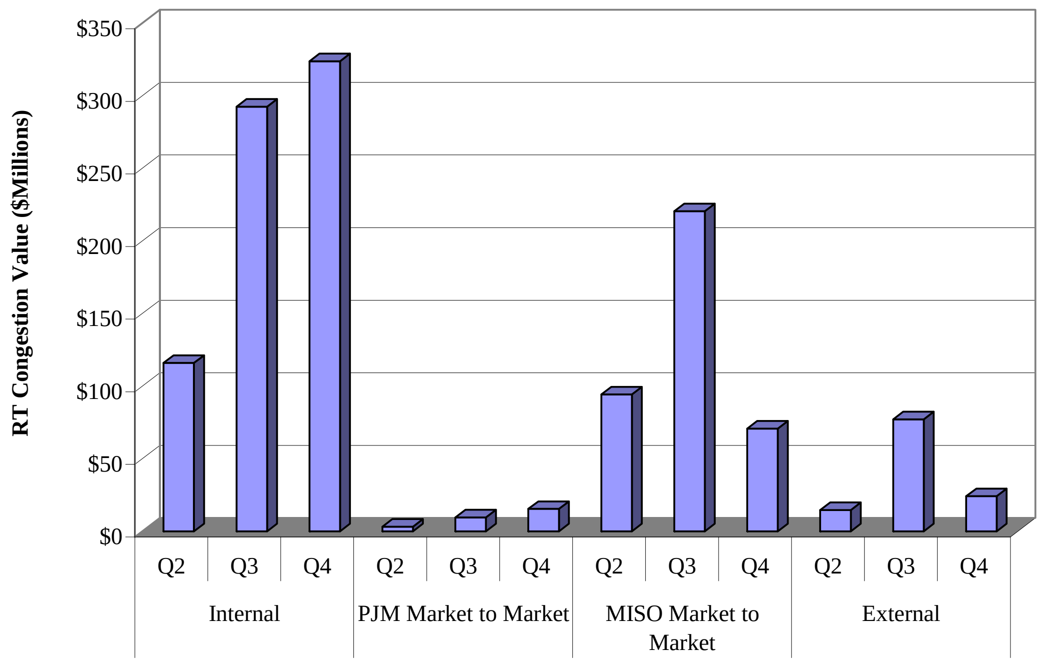
The total value of real-time congestion was estimated to be $1.2 billion. This is higher than the total congestion costs collected by the Midwest ISO because there are a large quantity of power flows across the Midwest ISO system for which no congestion costs are collected (i.e., loop flows caused by activity in other areas).

Figure 40 shows that most of the congestion occurred in the Central and East regions (East and WUMS). Congestion values increase under peak load conditions in July and August, though they remained high into the fall. Congestion values in the fall were impacted by high natural gas prices because the high fuel prices increased the generator redispatch costs. Relatively high congestion in the West was caused by an unusual series of events related to generation and transmission outages, as well as normal winter peaking of load in the northern areas. Figure 40 also shows that the average number of constraints that are binding at any point in time (i.e., during each interval). The number of constraints typically binding in each month rose to its highest level of 2.2 constraints per interval in September. The constraint frequency averaged more than 1.5 constraints per interval over the nine-month period.

To better identify the real-time sources of congestion, we have also calculated the value of congestion by type of constraint. Figure 41 shows these results for the following constraints:

- The 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);[5]
- The PJM constraints that are coordinated (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).

Figure 41: Value of Real-Time by Type of Constraint
2005



5 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 41 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 90 percent of the congestion value. It is notable that a sizeable portion of this congestion was on the market-to-market constraints, which indicate 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, one constraint is responsible for more than 30 percent of this congestion.

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, which is not unexpected. 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.

Figure 42 shows the calls by the Midwest ISO for TLRs and associated transaction curtailments in 2004 and 2005. There are various TLR levels. We include levels 3 though 5 in Figure 42, which are the levels that result in curtailments. Level 3 results in non-firm curtailments. Level 4 results in commitment or redispatch of specific resources or other operating procedures to manage specific constraints, and Level 5 results in curtailment of firm transactions.

Figure 42: TLR Events and Transactions Curtailed 2004-2005

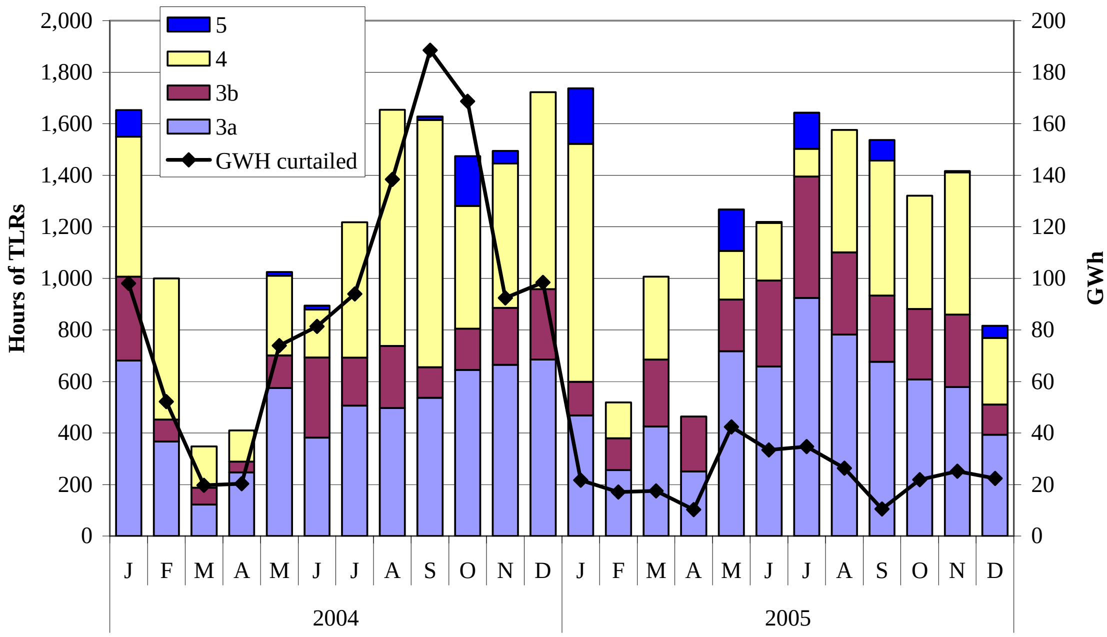


Figure 42 shows that the TLR calls by the Midwest ISO have decreased only slightly in 2005 after the implementation of the energy markets. The TLRs called on the Midwest ISO flowgates (level 3 and above) still account for about 54 percent of all TLRs called in the Eastern Interconnect.

As discussed above, the implementation of the markets was not expected to reduce the TLR calls. When a constraint is binding in the Midwest ISO energy market, it invokes the TLR procedures to ensure others outside of the Midwest ISO that contribute to the congestion assist in relieving it. However, the curtailments were expected to decrease substantially since most of the relief for the Midwest ISO constraints is now provided efficiently by the Midwest ISO energy markets, rather than via transaction curtailments. The figure confirms that curtailments have decreased dramatically. 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 versus 2004.

These reductions in curtailments indicate substantial efficiency improvements resulting from the nodal markets. In prior reports, we showed that the TLR process is inefficient. In particular, we found the process can lead to more than three times the curtailments to manage congestion on average than the quantity of economic redispatch needed. It also resulted in less timely and less accurate control of the system – resulting in lower reliability.

To show where the constraints have occurred that have resulted in TLRs, Figure 43 shows the monthly quantity of TLRs called in 2004 and 2005 by selected regions. Kentucky is shown separately from the Central region to show the relatively high number of TLR events in 2005 that occurred in that area.

Figure 43: TLR Events by Duration
April - December 2004 and 2005 by Region

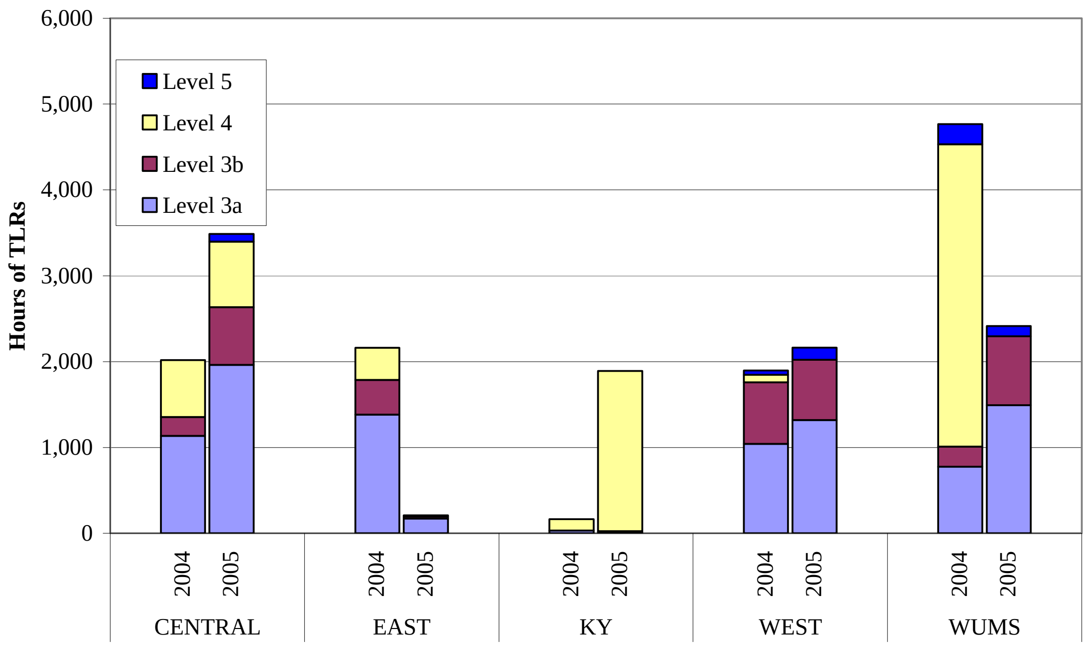


Figure 43 shows that TLR levels were reduced in the East and into WUMS. The vast majority of the reduction into WUMS is the elimination of the level 4 TLRs. Prior to the Midwest ISO markets, American Transmission Company ("ATC") redispatched generation when level 4 TLRs were called. This redispatch is now done through the Midwest ISO energy market so many of these TLRs do not need to be called (i.e., the constraints for which external entities have little impact).

The figure also shows that TLR events increased in the Central and Kentucky areas. This was due in part to flows from north to south associated with exports to TVA and local load pockets in and around Louisville. As discussed in more detail later in this section, a substantial contributor to the increased north to south flows is non-firm transmission service sold by PJM to TVA. This service was initially not coordinated under the market-to-market provisions in the JOA. Steps have been taken to establish an interim procedure to better manage this service until a long term solution is developed. The TLRs in Kentucky are generally level 4 because this level must be called before any reconfiguration of generation or transmission is done on the LGEE system, which is often necessary to manage the constraints in that area.

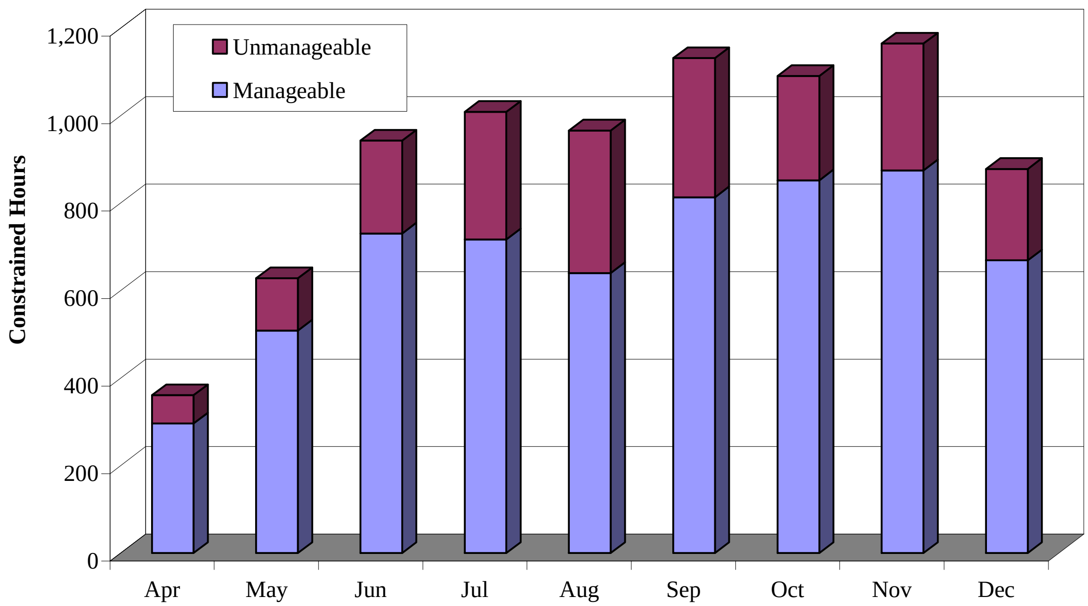
D. Congestion Manageability

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 in 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 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 44 shows the frequency with which constraints were unmanageable in each month.

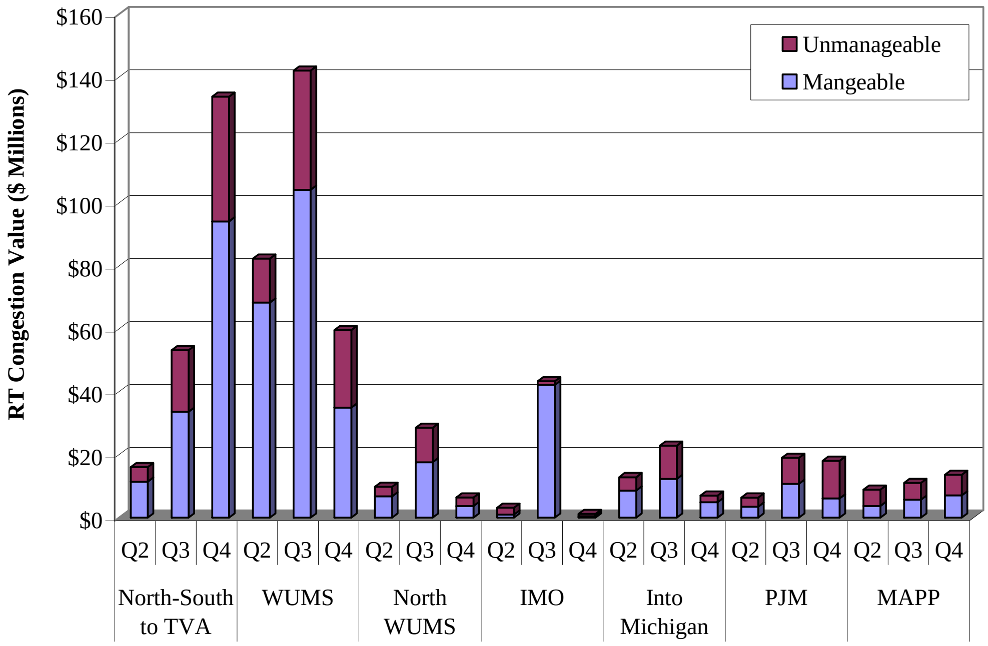
Figure 44: Congestion and Manageability April - December 2005



Overall, 75 percent of the congestion was manageable on a 5-minute basis. From April to December, the percentage of unmanageable congestion events trended up slightly in the first few months to a peak of 34 percent in August. The unmanageable congestion decreased to an average of 24 percent over the last 3 months of the year. Later in this section, we discuss the factors that contribute to unmanageable congestion in the Midwest ISO region and provide recommendations that should substantially reduce its frequency.

The next analysis shows the portion of the congestion on selected interfaces, indicating the portion of the real-time congestion that was manageable. The purpose of this analysis, which is shown in Figure 45, is to show how the manageability of the congestion at different locations varies.

Figure 45: Value of Real-Time Congestion by Path



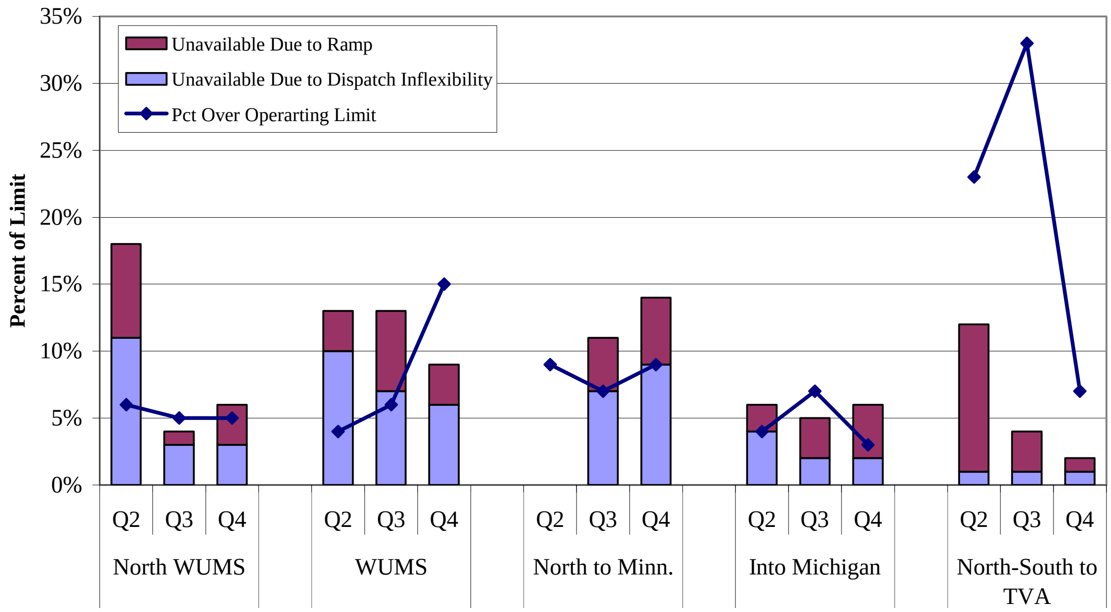
This figure shows that the highest-value congestion was on the interfaces into the WUMS area, as expected. The unmanageable congestion into this area was caused, in large part, by generator inflexibility (inflated EcoMin levels on generators that cause power flows to increase over the constraint). This inflexibility often resulted in negative real-time prices in Minnesota. The figure also shows that the north-south path to TVA became heavily congested in the fourth quarter of 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. However, PJM has subsequently taken steps to limit this service when the Midwest ISO has no ATC on the Midwest ISO flowgates. In the longer run, we recommend that the RTOs coordinate this export service under the market-to-market provisions of the JOA.

The PJM market-to-market congestion must be interpreted differently than the others. It is shown as “unmanageable” if the requested relief cannot be provided at a redispatch cost that is less than PJM’s marginal redispatch costs. This prevents the Midwest ISO from inefficiently incurring higher redispatch costs than PJM to manage the flows on a PJM interface. Hence, a much higher portion of the congestion is likely to show as unmanageable on these constraints.

Our next analysis evaluates two components of suppliers' offer patterns that contribute to instances when transmission constraints are "unmanageable". The first is the submission of inflexible dispatch parameters, which is 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). This can contribute to congestion when the resource's output increases the flow on a line. A second factor that contributes to unmanageable congestion is slow 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 the dispatch inflexibility, this limits the Midwest ISO's ability to redispatch generation through the market to manage congestion.[6]

Our next analysis evaluates the effects of these two factors by estimating the amount of congestion relief (capability to reduce the flow on a constraint) that was unavailable due to each of these factors. Figure 46 shows the results of this analysis by constraint. To show how significant the unavailable relief quantities are, the figure also shows the average percentage that the flow was over each constraint's limit when it was unmanageable ("average violation").

Figure 46: Congestion Relief Unavailable Due to Offer Parameters Selected Paths

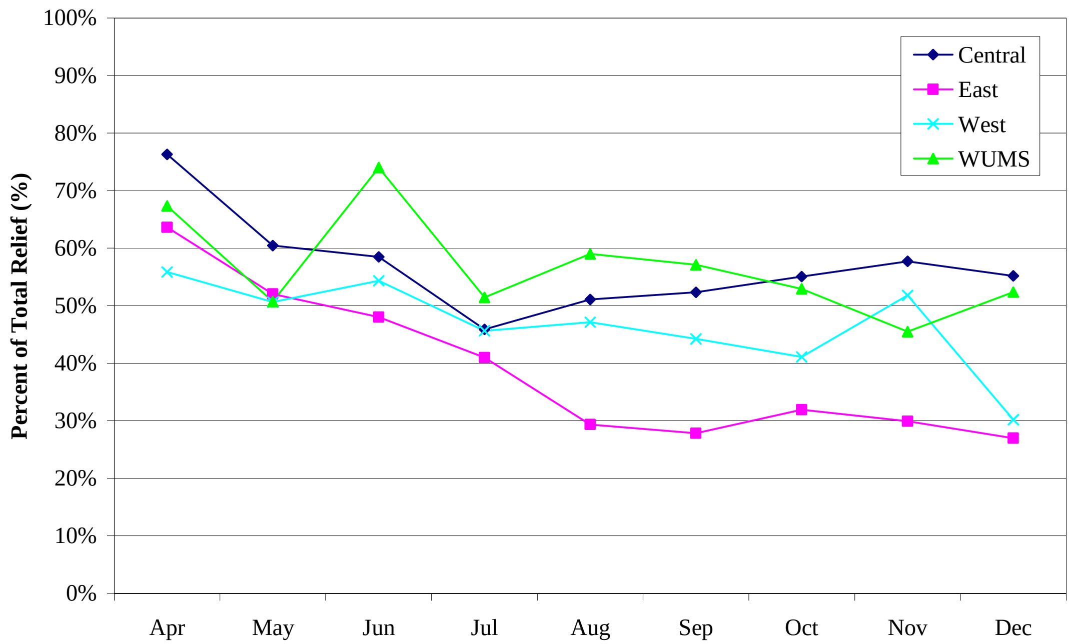


6 The Midwest ISO has other procedures it can employ to manage the flow over constrained interfaces.

The results show that on all of the paths, with the exception of the N-S to TVA path, the congestion relief quantity that could have been available physically would have been enough to manage the congestion. The TVA path is a different case from the others – the violations on this path were largely due to excessive non-firm schedules by PJM rather than by generator inflexibility.

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 47. We refer to this as "decremental relief" because it is achieved by decrementing the generation.

Figure 47: Decremental Relief Quantities Offered by Region April - December 2005



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. It shows that with the exception of the Central region, offered flexibility has generally declined throughout the year. The East region, in particular, showed significant declines in offer flexibility.

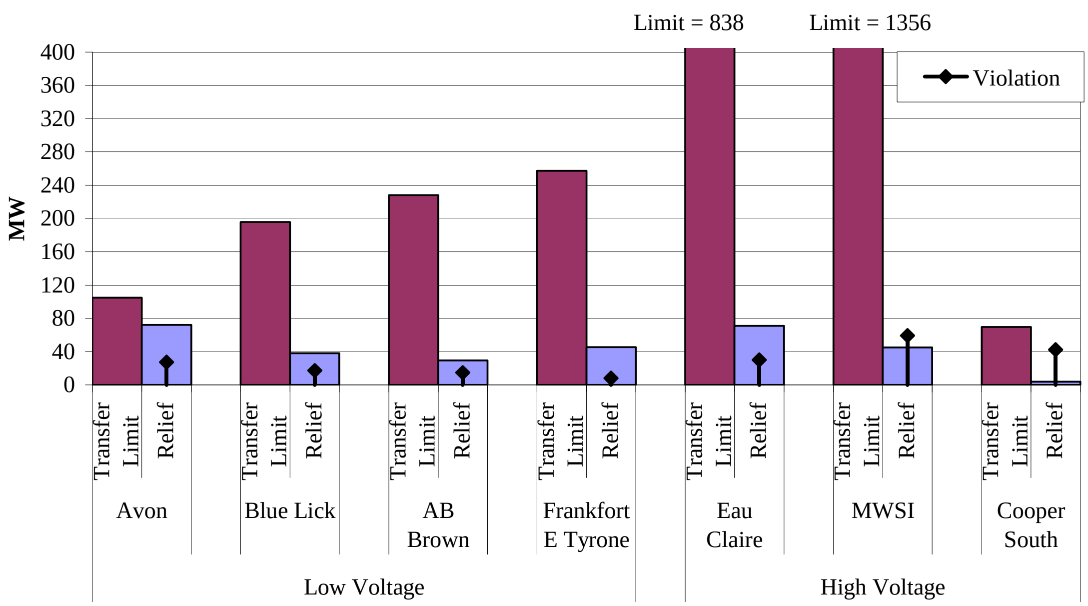
We attribute the inflexibility to a number of reasons.

- 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 – settlement rules to eliminate this concern are being developed. However, the prior figure shows that this conduct began at the outset of the market before any price volatility had occurred.
- Finally, there has been evidence that some participants have deliberately engaged in over-production to cause substantial congestion on key transmission interfaces. In such cases, the IMM has investigated to determine whether the conduct warrants referral to FERC for a potential sanction. All such conduct that was detected in 2005 has been remedied.

In addition to participants' contribution to the instances of unmanageable congestion, there is a parameter in the Midwest ISO's real-time market software that 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 to manage a constraint.

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 48 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 48: 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 based on raising the excluded units' output to its maximum or reducing the excluded units' 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 that we sampled. This effect of GSF cutoff parameter is particularly large for the 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. Currently, the same parameter is used for load and generator nodes. Since there are many times more load nodes than generator nodes, and given the Midwest ISO's practical concerns regarding the quantity of data that would be produced and passed among its real-time systems if the parameter were reduced, we believe it is be reasonable to initially keep the 2 percent parameter for load nodes.

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.

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.

We evaluate hourly FTR auction values relative to the value of day-ahead congestion. Our calculations are computed relative to the Cinergy Hub. We use the Cinergy Hub because more FTRs per month are purchased to and from the Cinergy Hub than any other node. Figure 49 and Figure 50 show the values for WUMS and West regions. The prices in these regions are the most affected by the frequent congestion into WUMS.

Figure 49: Comparison of FTR Auction Prices and Congestion Value WUMS Area

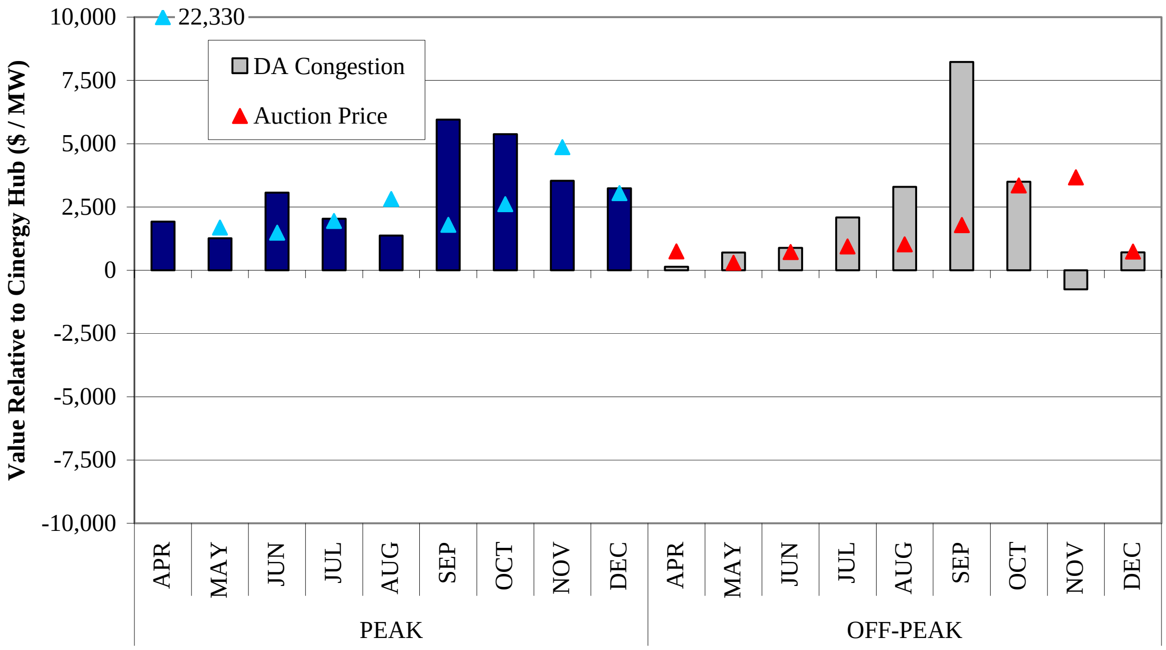
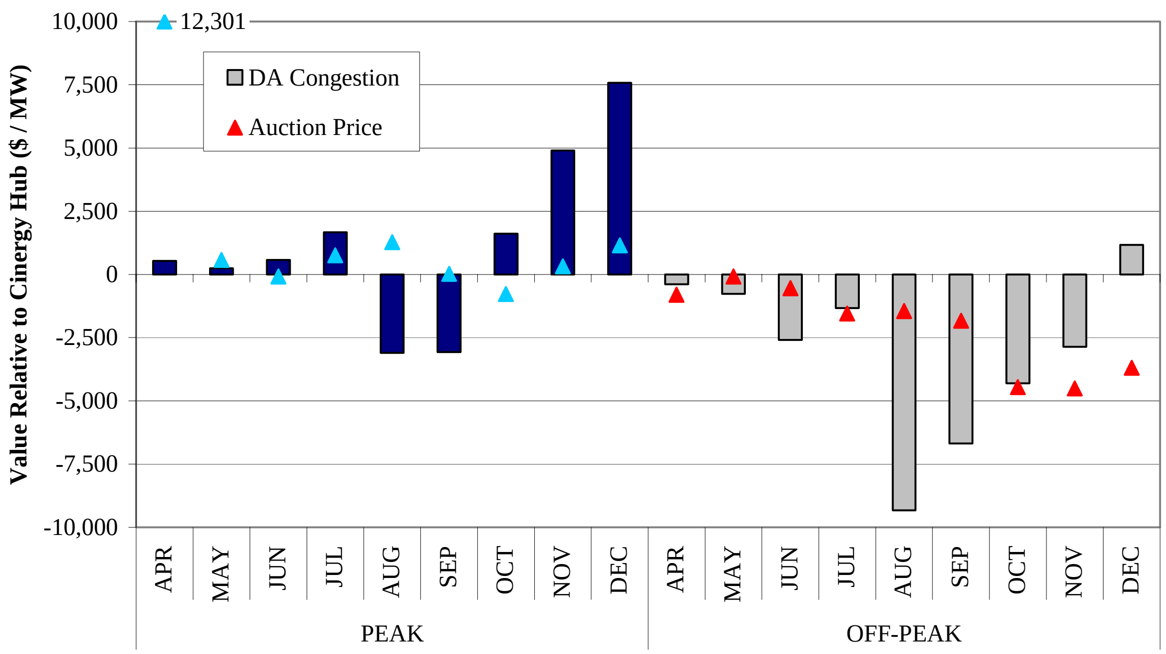


Figure 50: Comparison of FTR Auction Prices and Congestion Value Minnesota Hub



These figures show that as the market opened in April, the FTR auction did not closely reflect the value of the day-ahead congestion. The peak FTR auction prices deviated from DA congestion by $20,000 per MW in WUMS and $12,000 per MW at the Minnesota Hub. However, the market in the WUMS region showed much better convergence between the FTR and actual congestion results in the last 8 months of 2005. For the May to December period, average congestion costs exceeded the FTR clearing price by less than $700 for the peak hours and less than $800 in the off-peak market. In September, congestion peaked due to transmission and generation outages.

The congestion and FTR results for the Minnesota Hub were less consistent. With the exception of the FTR prices in April, congestion values and FTR prices were low in the first four months of the market's operation. Congestion in Minnesota reversed direction at the end of the year due to the outage of Arnold-Hazelton and high winter loads that caused constraints to bind *into* Minnesota. The FTR prices did not converge well in peak hours, likely due in part to the erratic congestion patterns affecting prices in Minnesota.

Figure 51 and Figure 52 show the same analysis for the Michigan Hub and the IMO interfaces.

Figure 51: Comparison of FTR Auction Prices and Congestion Value Michigan Hub

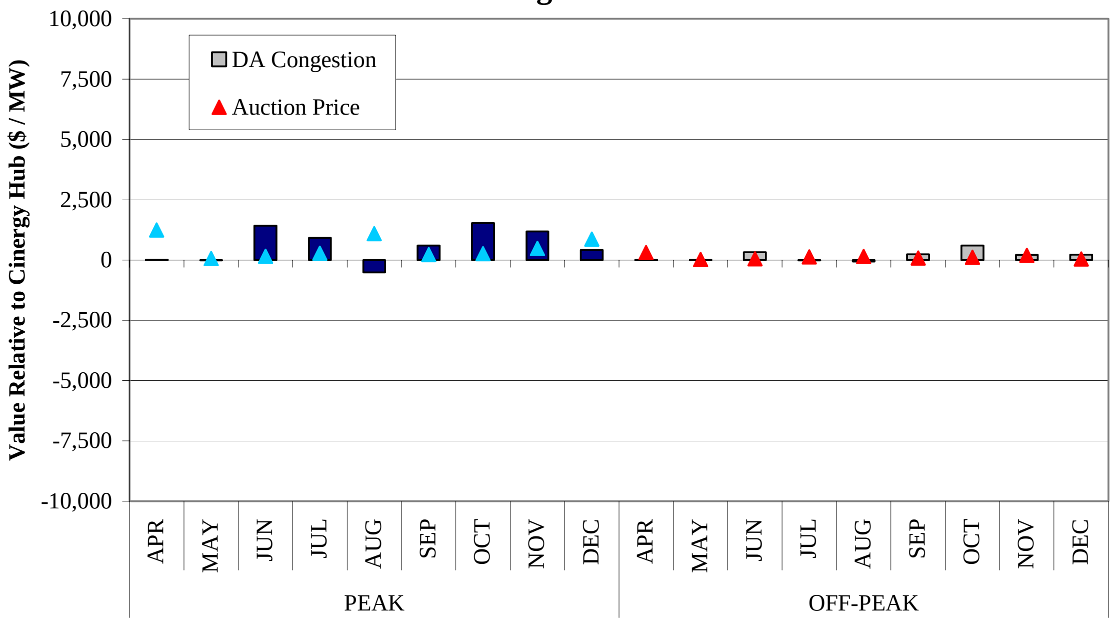
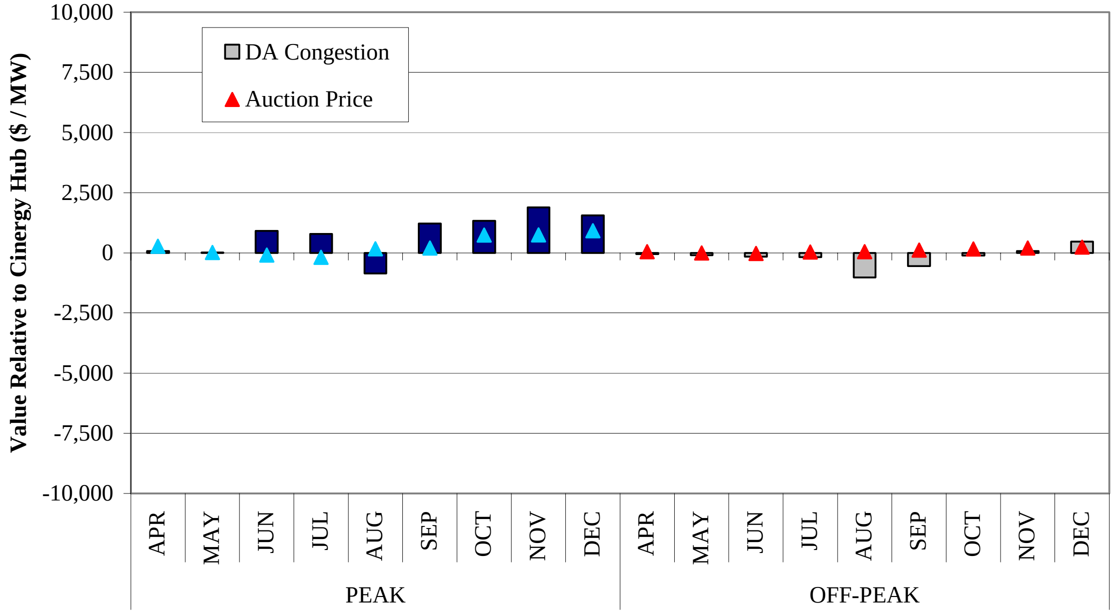


Figure 52: Comparison of FTR Auction Prices and Congestion Value IMO



In general, the FTR auction prices and the corresponding congestion levels at the Michigan hub and IMO are much less than in either WUMS or the Minnesota Hub. In absolute terms, the congestion values and FTR prices correspond reasonably well. In relative terms, the FTR prices frequently do not accurately reflect the actual congestion. In general, the FTR prices are extremely low, understating the actual prevailing congestion.

VI. Competitive Assessment

This section provides a competitive assessment of the Midwest ISO markets in 2005. In includes both a structural analysis of the market, as well as an evaluation of the participants' conduct in the first year of the market's operation.

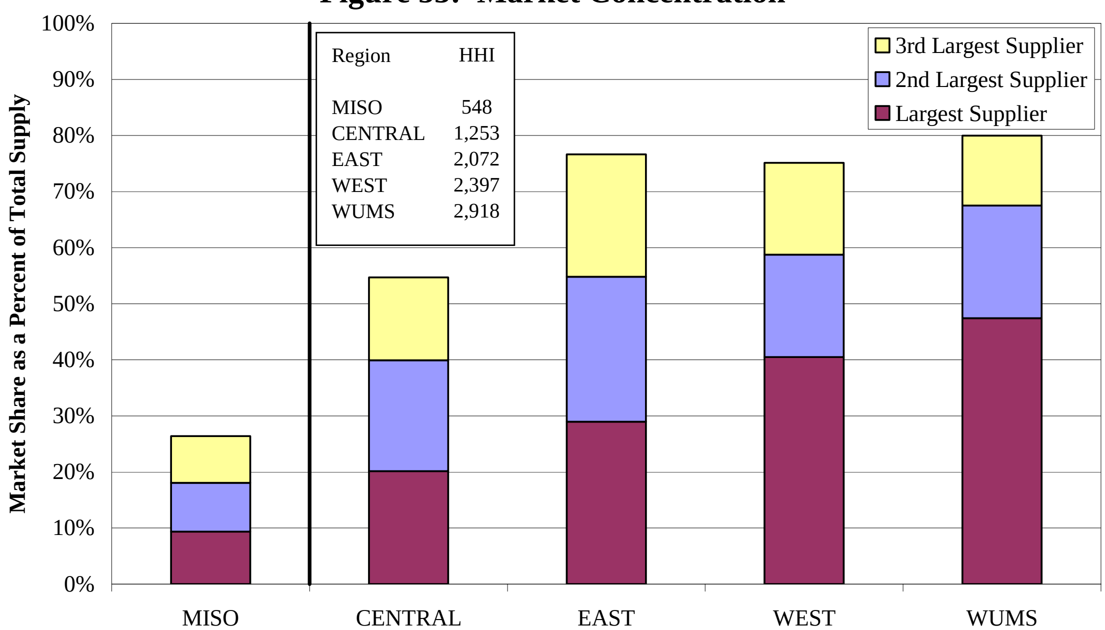
A. Market Structure

This first subsection provides three structural analyses of the market. It begins by providing an overview of the concentration of the market as a whole and in various sub-regions. It then provides two analyses that indicate when suppliers in the Midwest ISO region are "pivotal", i.e., needed to serve load reliability or resolve transmission constraints.

1. Market Concentration

The first analysis of market structure shows the market's concentration. This is measured using the Herfindahl-Hirschman Index ("HHI"). HHIs are calculated by summing the squares of each supplier's market share. The antitrust agencies generally characterize markets with HHIs of greater than 1800 as highly concentrated. The HHI provides only a general indication of market conditions and is not a definitive measure of market power because it does not consider demand, network constraints, and load obligations. The HHI values for the Midwest ISO as a whole and each sub-region are shown in Figure 53.

Figure 53: Market Concentration

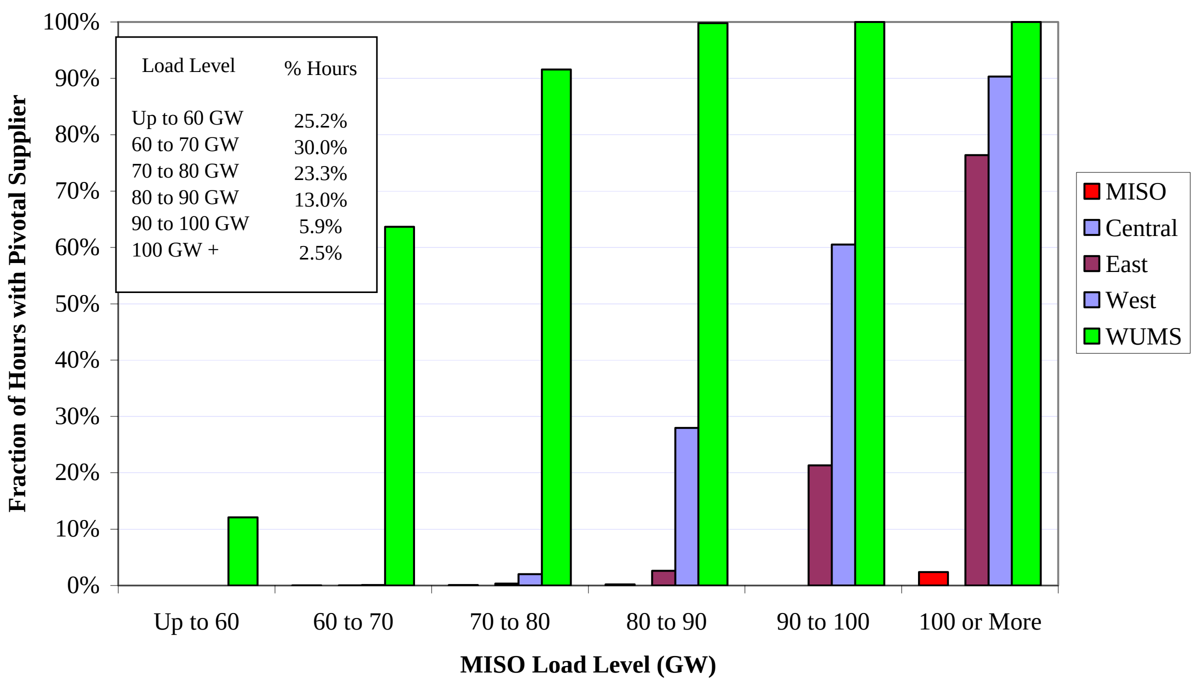


The market concentration of the entire the Midwest ISO region is relatively low at an HHI of 548. The largest 3 suppliers combined have a total market share less than a 30 percent. This is generally conducive to robust competition. However, each of the Midwest ISO sub-regions is highly concentrated with the exception of the Central region. The HHIs are higher than in other RTOs' sub-regions because the vertically-integrated utilities in the Midwest ISO have not divested substantial amounts of generation as in other regions, such as New York and New England. Such divestitures generally reduce market concentration because the assets are typically sold to a number of different entities.

2. Residual Supply Index

As noted above, market concentration does not allow one to draw reliable inferences regarding the competitiveness of electricity markets because it ignores a number of key factors. The next two analyses calculate metrics that provide more accurate indications of potential competitive concerns in the Midwest ISO energy markets. The first metric that is useful for evaluating competitive issues in electricity markets is the residual demand index ("RDI"). The RDI metric indicates the portion of the load in an area that can be satisfied without the resources of the largest supplier. Figure 54 shows the RDI by load level in different areas in the Midwest ISO.

Figure 54: Pivotal Supplier Frequency by Load Levels in 2005

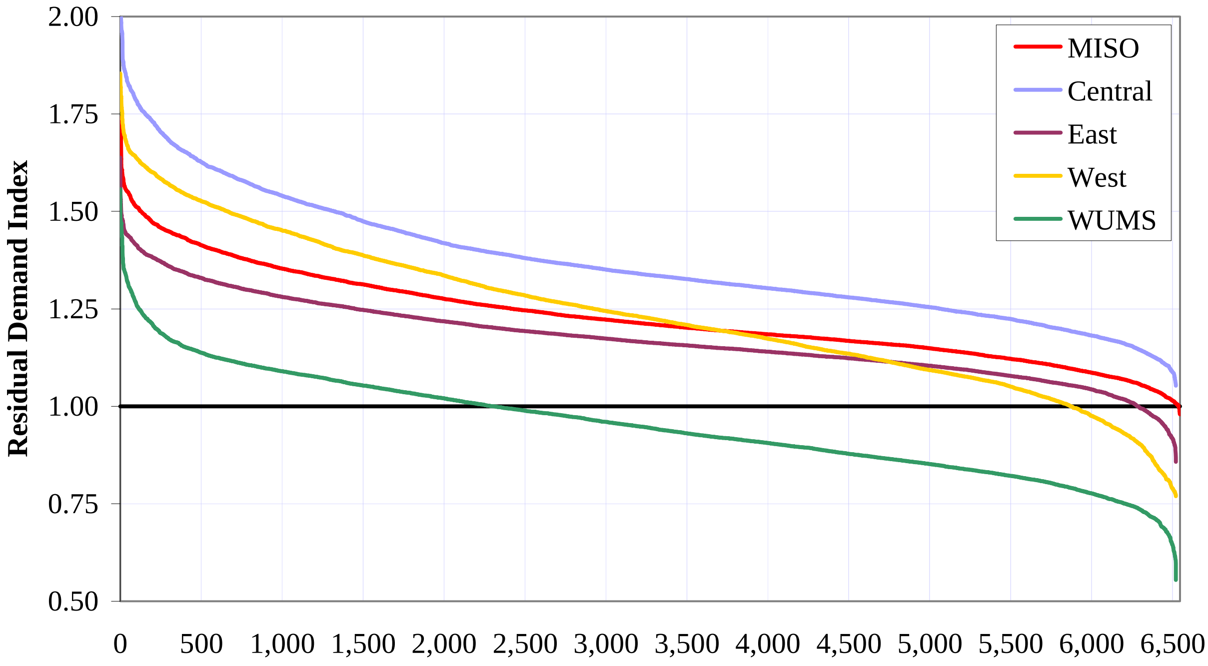


In calculating the RDI, we include all import capability into the area, not just the imports that were actually scheduled. In general, the RDI will decrease as load increases since increasing quantities of rivals' generation will be needed to satisfy the load. An RDI > 1 means that the load can be satisfied 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 54 shows that there is limited competition in the WUMS region at all load levels. When load is higher than 60 GW (75 percent of the time), there is a pivotal supplier in WUMS between 60 percent and 100 percent of the hours. The West and East regions exhibit a pivotal supplier in a substantial number of hours only when load exceeds 80 GW (over 20 percent of the hours).

To provide additional information regarding how pivotal the largest supplier is in different numbers of hours, Figure 55 shows the residual supplier index in the form of a duration curve from highest index (most competitive) to lowest index (least competitive).

Figure 55: Residual Demand Index Duration Curves
2005: All Hours



These curves show there were no hours with a pivotal supplier in the Central region and very few hours with a pivotal supplier in the Midwest ISO region as a whole. However, the WUMS region has one or more pivotal suppliers in more than two-thirds of the hours during the study period (April – December 2005). 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 special treatment of WUMS as a Narrow Constrained Area ("NCA") under the mitigation measures in the Midwest ISO tariff. The West had a pivotal supplier in about 10 percent of hours in 2005 and the East had a pivotal supplier in about 5 percent of the hours.

3. Constraint-Specific Pivotal Suppler Analysis

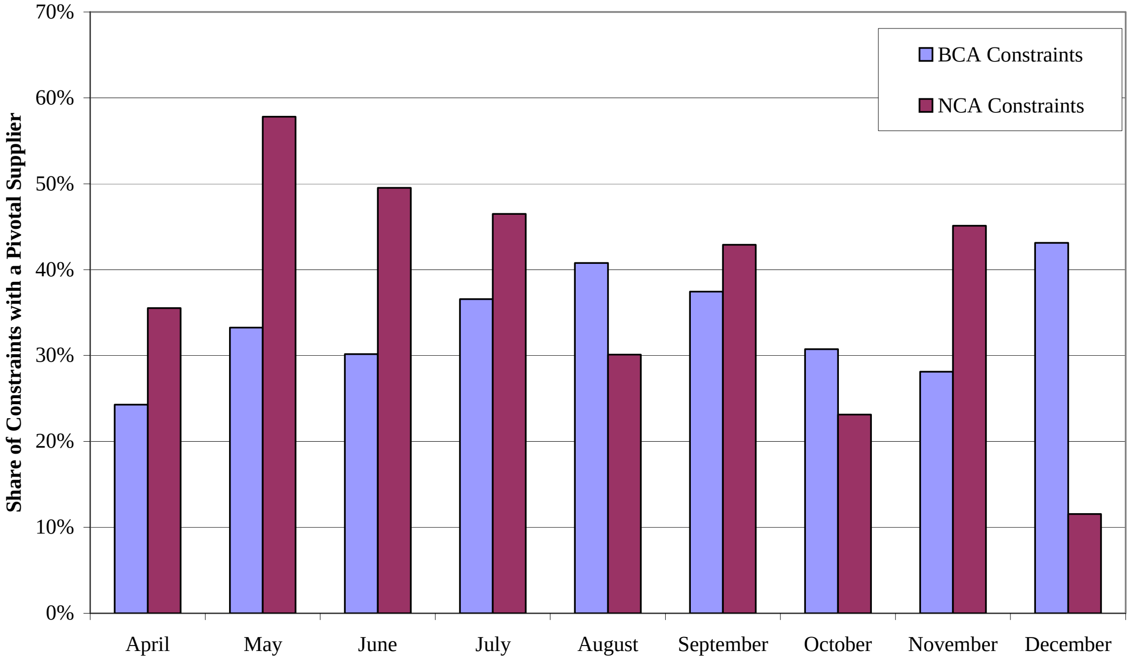
While the pivotal supplier indications in the prior sub-section are useful for evaluating the competitiveness of the market, suppliers are pivotal in a sub-region only if the constraints into the sub-region are binding. Additional accuracy in identifying pivotal suppliers can be achieved by performing a pivotal supplier analysis on a constraint-specific basis. This involves identifying when a supplier's resources are needed to manage a constraint and, therefore, may have local market power.

Based on our past studies, such market power exists across the entire Midwest ISO region. However, the market power mitigation to address local market power outside of the WUMS (i.e., in Broad Constrained Areas or "BCAs") has expired, leaving the market vulnerable to substantial market power abuses.

The next set of analyses identify significant 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 significantly affect the flows over the constraint are those that are near the constraint. If they are all owned by the same supplier, this supplier is likely to be pivotal.

Figure 56 shows the portion of the active constraints that have at least one pivotal supplier by month in 2005.

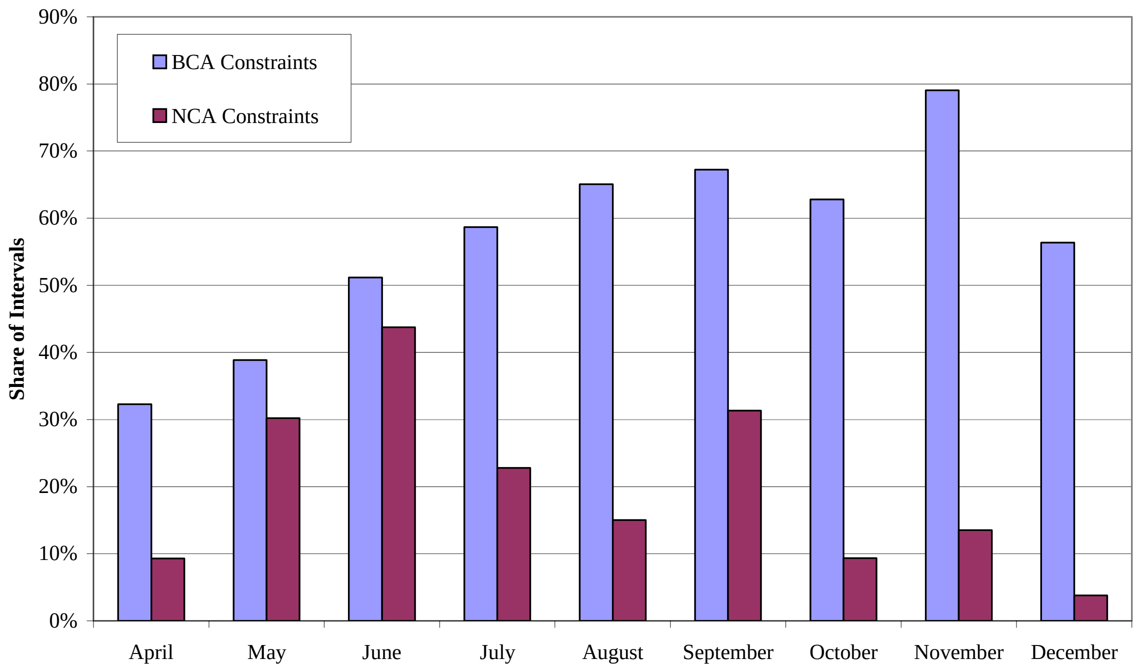
Figure 56: Percent of Active Constraints with a Pivotal Supplier



This analysis reveals that thirty-four percent of the active BCA constraints have a pivotal supplier and 41 percent of the active NCA constraints have a pivotal supplier. These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of the BCA constraints also create substantial local market power.

Figure 57 shows the overall percentage of intervals during the market's operation in 2005 when at least one supplier is pivotal for a BCA or NCA constraint. This analysis differs from the prior analysis because it incorporates how frequently the BCA and NCA constraints are active. Therefore, it indicates how frequently significant local market power may be a problem in one or more locations with the Midwest ISO region.

Figure 57: Percent of Intervals with Least One Pivotal Supplier



This analysis shows that there was an active BCA constraint with at least one pivotal supplier in 57 percent of the hours during 2005. These values rose over the year and peaked at nearly 80 percent of the hours in November 2005. This increase is attributable to the fact that BCA constraints were active more frequently later in the year.

The analysis also indicates that there was an active NCA constraint with a pivotal supplier in almost 20 percent of the hours. The NCA ratios decreased over the year because the NCA constraints were active less frequently. These results indicate that the BCA and NCA mitigation continues to be essential. Therefore, the recent decision by FERC to not renew the BCA mitigation measures in the Midwest ISO tariff raises serious market power concerns in the Midwest.

When participants possess local market power and, therefore, have the ability to substantially increase market prices or RSG payments, they may not choose to exercise that market power for a variety of reasons. The next section evaluates participants conduct during the Midwest ISO's first year of operation.

B. Participant Conduct

In this section, we analyze participant conduct to determine whether it is consistent with competitive conduct 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 an economic unit is unavailable to produce output. This is usually accomplished by claiming an outage or by derating the resource. We examine both of these issues in this subsection.

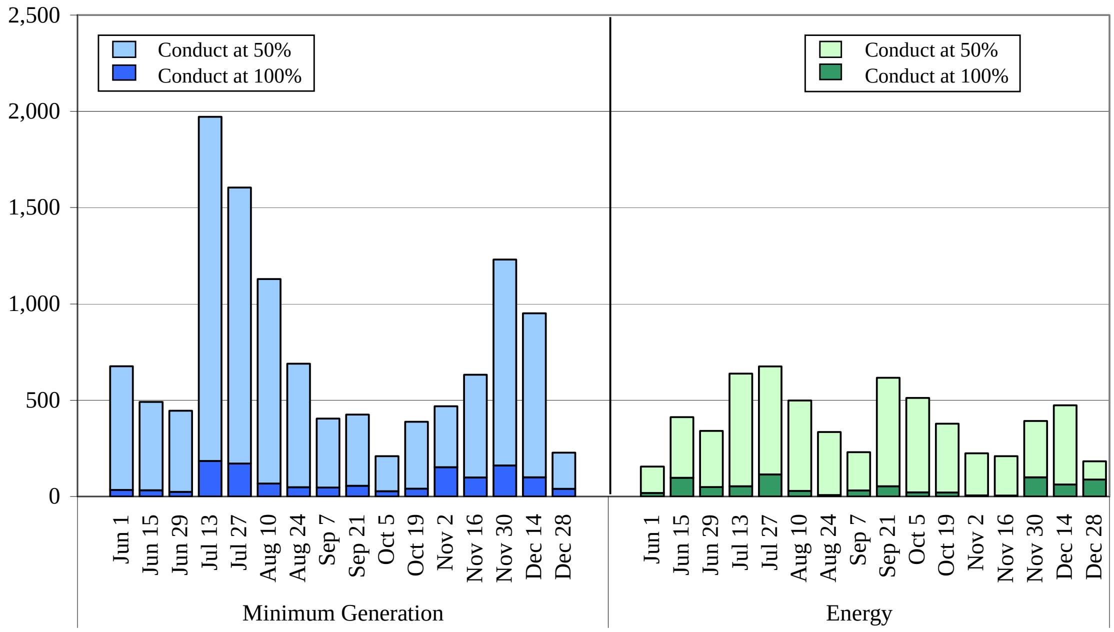
1. Economic Withholding

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 as a result of environmental considerations, must forego revenue in a future period when they produce in the current period. These units incur an inter-temporal opportunity cost 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 resources' "reference levels" that are intended to reflect the resources' marginal costs. We use these reference levels for the analyses below. The mitigation measures also include a threshold that defines how far above a resource's reference levels the supplier would have to offer to potentially warrant mitigation (this is referred to as the "conduct test" for mitigation). Figure 58 shows the average amount of generation offered at levels that exceed the conduct thresholds on a biweekly basis.

Figure 58: Conduct at 100 percent and 50 percent of Conduct Threshold Real-Time Market



The figure shows two panels. The left-hand-side shows the amount of generation that exceeds the conduct thresholds for minimum generation offers (i.e., no-load and energy offered up to a resource's EcoMin). The right-hand-side panel shows the amount of generation exceeding the conduct thresholds for the energy offers. The calculations are the average for each of the two-week periods from June to December. The analysis shows two values, one is for the amount exceeding 50 percent of market power mitigation conduct threshold in the Midwest ISO Tariff and the other is the amount exceeding 100 percent of the threshold.

The results in Figure 58 indicate that the average quantities exceeding the mitigation thresholds were very low. The quantities of energy 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. However, start-up and no-load offers can affect energy prices also when they change the pattern of generators committed.

Figure 58 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 and decommitment patterns). However, it can result in substantial RSG costs.

Although the analysis above is useful, it can include quantities that do not truly reflect economic withholding because the resources themselves are not 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 even at its competitive reference level and, therefore, is not being 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 as a result of having submitted 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 for quick start units this assessment is based on real-time market outcomes.

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 adjustments are necessary to estimate the actual output gap because some units are dispatched at levels lower than their three-part offers would indicate. This can be due either to transmission constraints, reserve considerations, or changes in market conditions between the time when unit commitment is performed 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.

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 gaps 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 one half of the mitigation thresholds. Figure 59 through Figure 62 shows results of our output gap analysis for each of the Midwest ISO sub-regions.

Figure 59: Real-Time Market Output Gap
Central Region

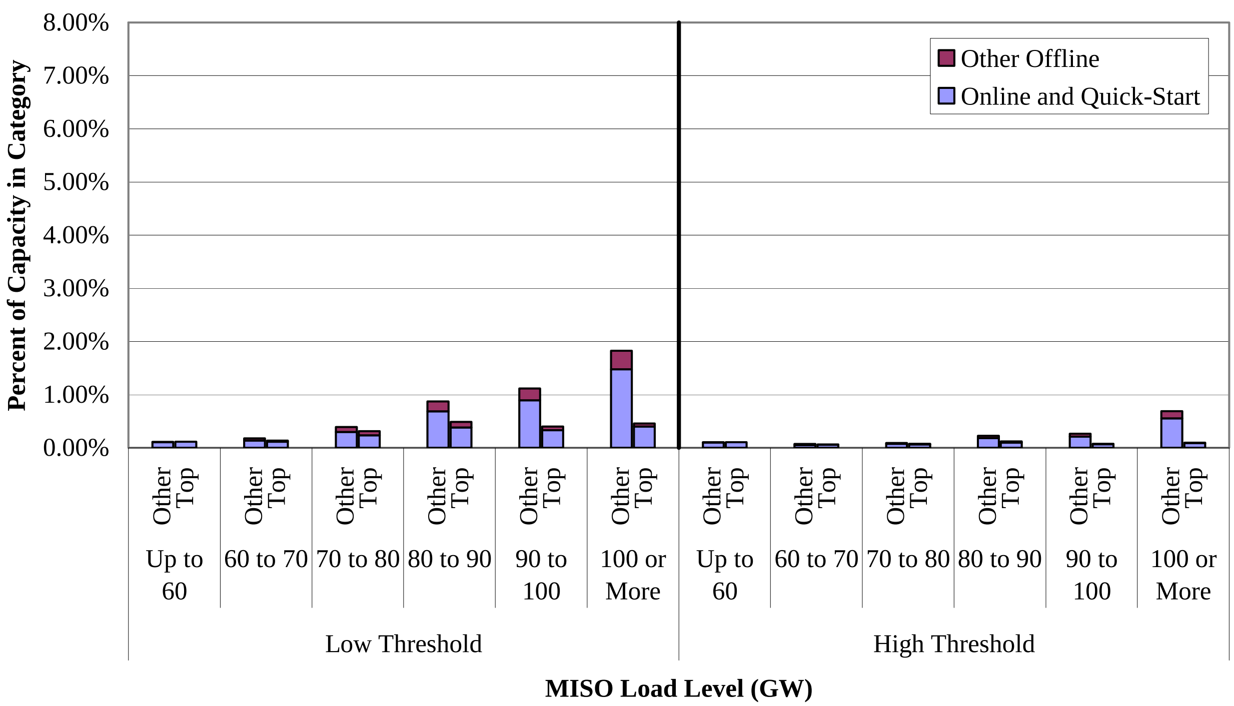


Figure 60: Real-Time Market Output Gap
East Region

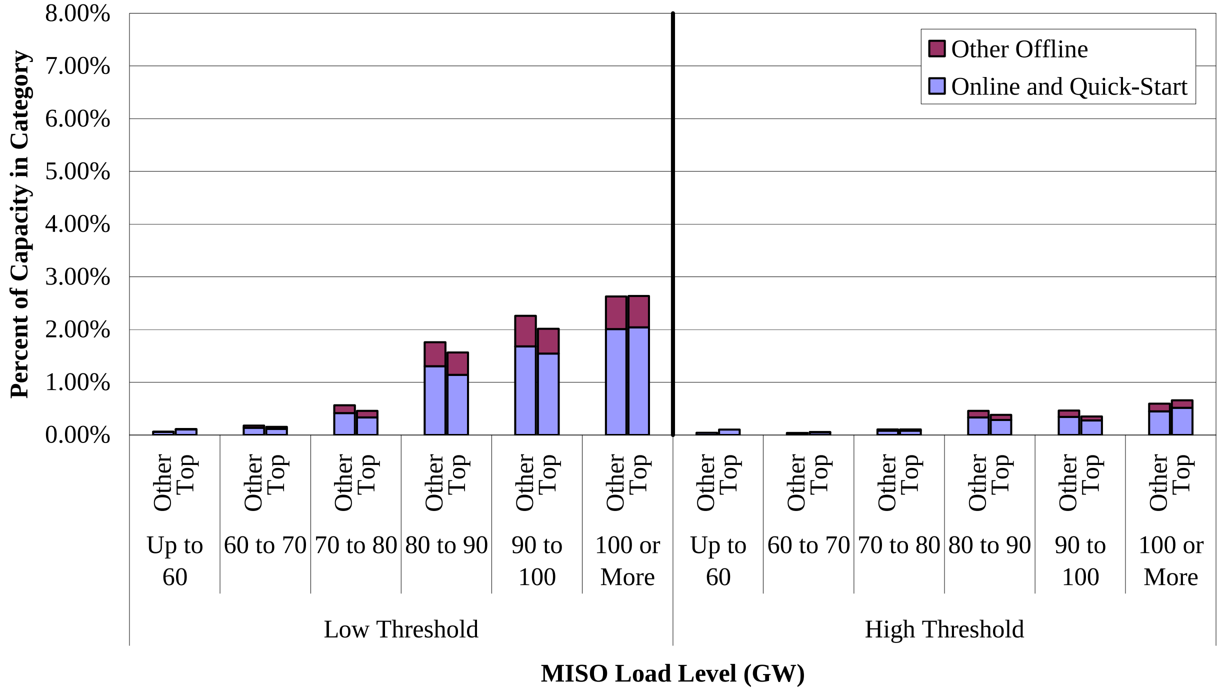


Figure 61: Real-Time Market Output Gap
West Region

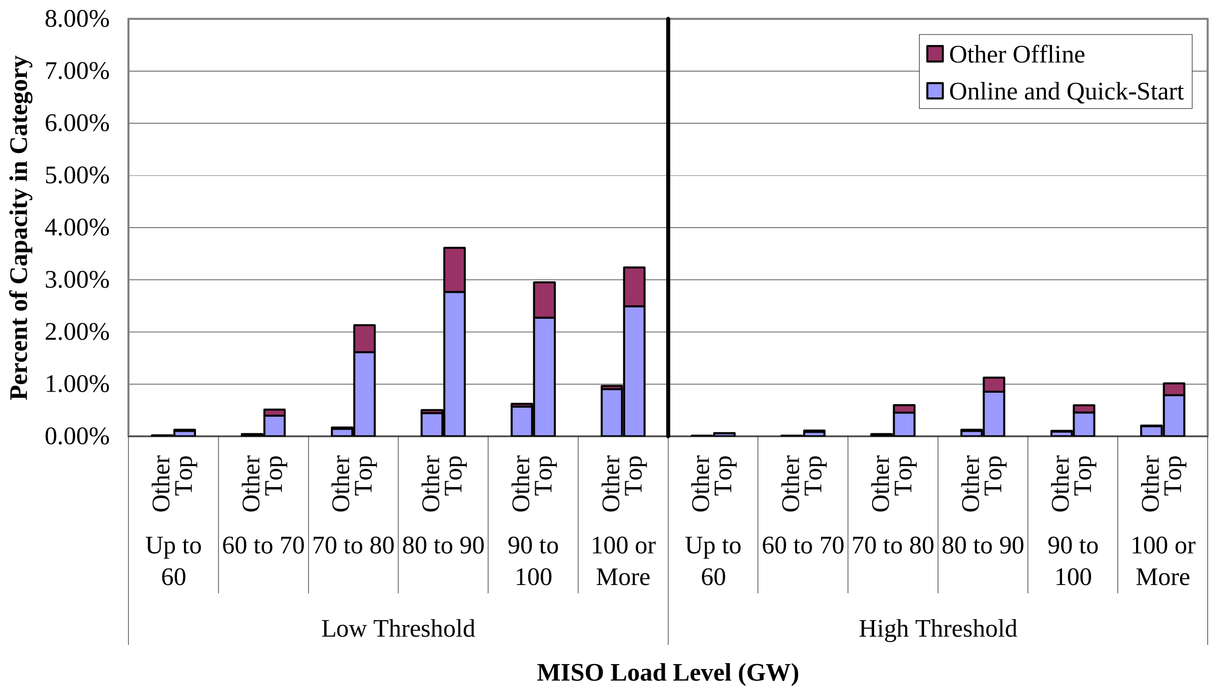
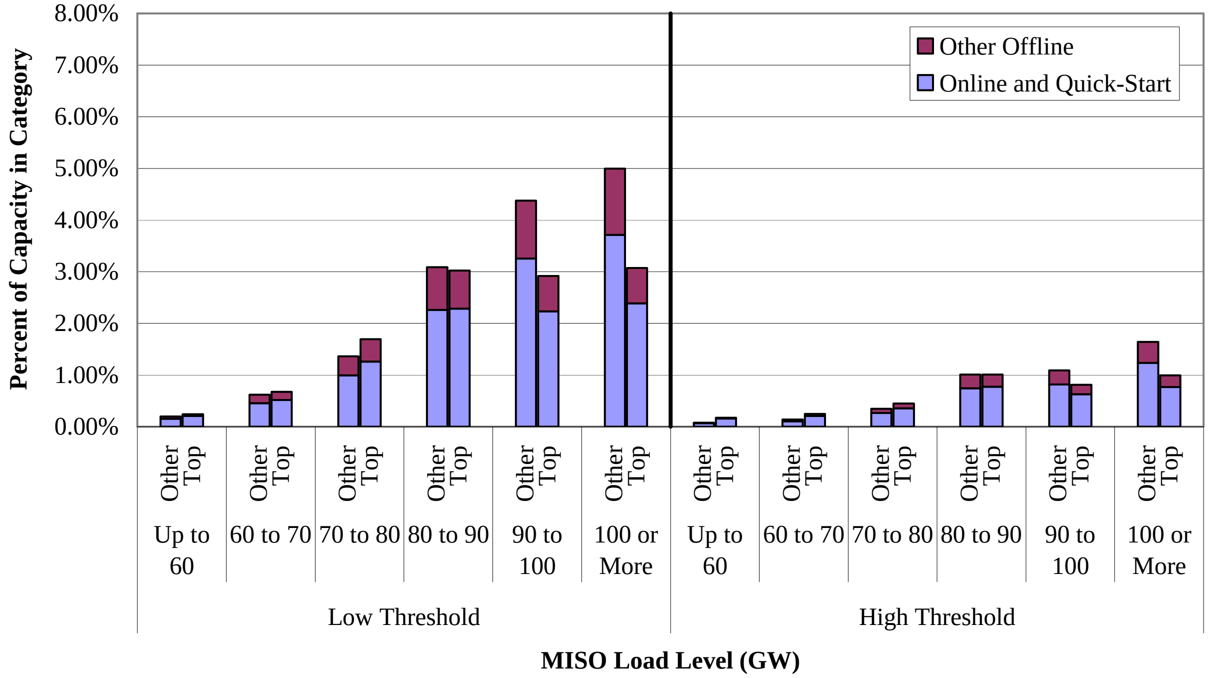


**Figure 62: Real-Time Market Output Gap
WUMS**



These figures reveal a number of important observations. First, the output gap quantities at the mitigation thresholds are less than 1 percent on average, which is extremely low. Next, the output gap levels at the lower threshold are also generally very low. It 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. Finally, with the exception of the West region, the output gap quantities for the largest suppliers in each region are lower than for other suppliers. Overall, these results indicate that the participants engaged in very little economic withholding and, thus, the results do not raise substantial competitive concerns.

2. Physical Withholding

This sub-section of the report examines forced outages and other non-planned deratings to assess whether they have occurred in a manner that may indicate potential 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 certain outages and deratings when they substantially affect the 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 may be justified or may represent physical withholding. Therefore, we evaluate them relative to load levels and participant size to detect patterns that would be consistent with potential physical withholding.

The figures below show these measures of forced outages and deratings by load level for the top two suppliers in each region and for other suppliers. Figure 63 through Figure 66 below shows these results for each of the Midwest ISO's sub-regions.

Figure 63: Real-Time Deratings and Forced Outages East Region

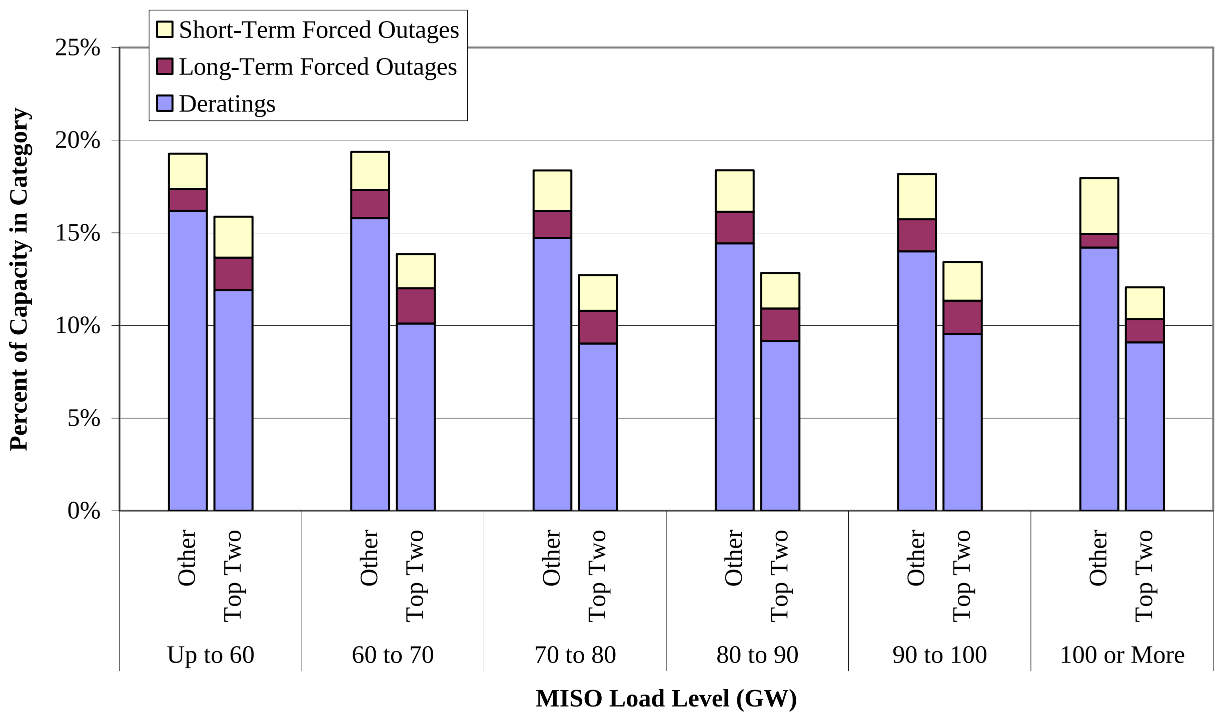


Figure 64: Real-Time Deratings and Forced Outages
Central Region

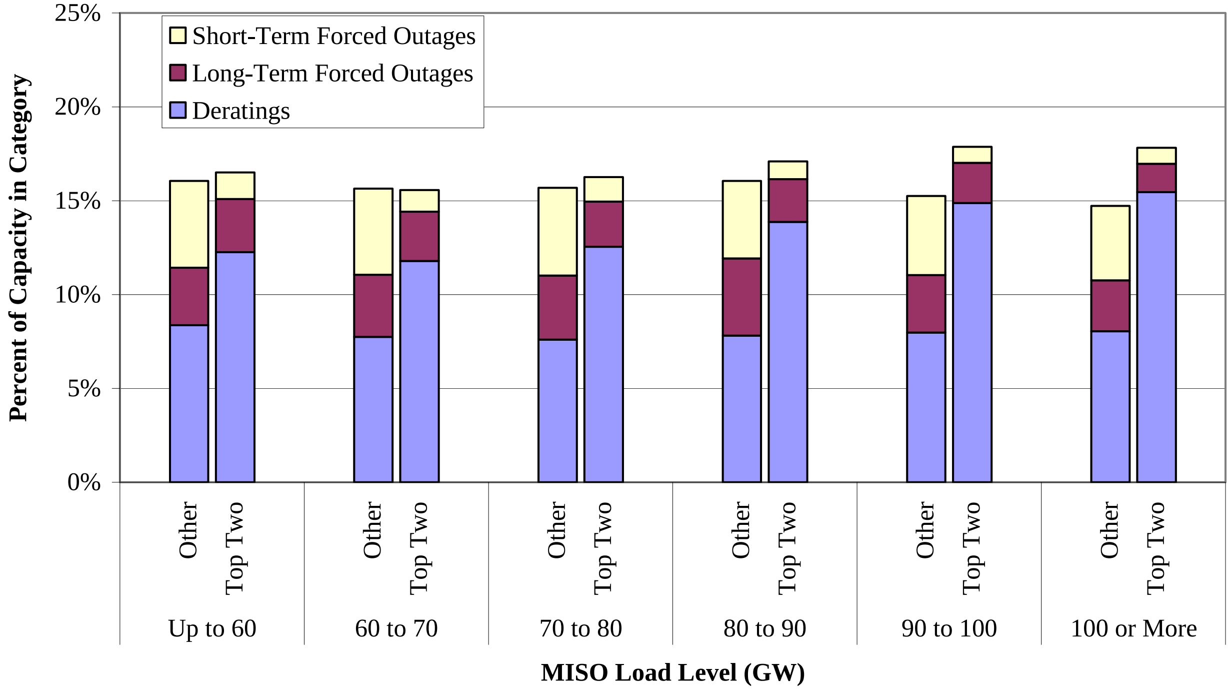


Figure 65: Real-Time Deratings and Forced Outages
West Region

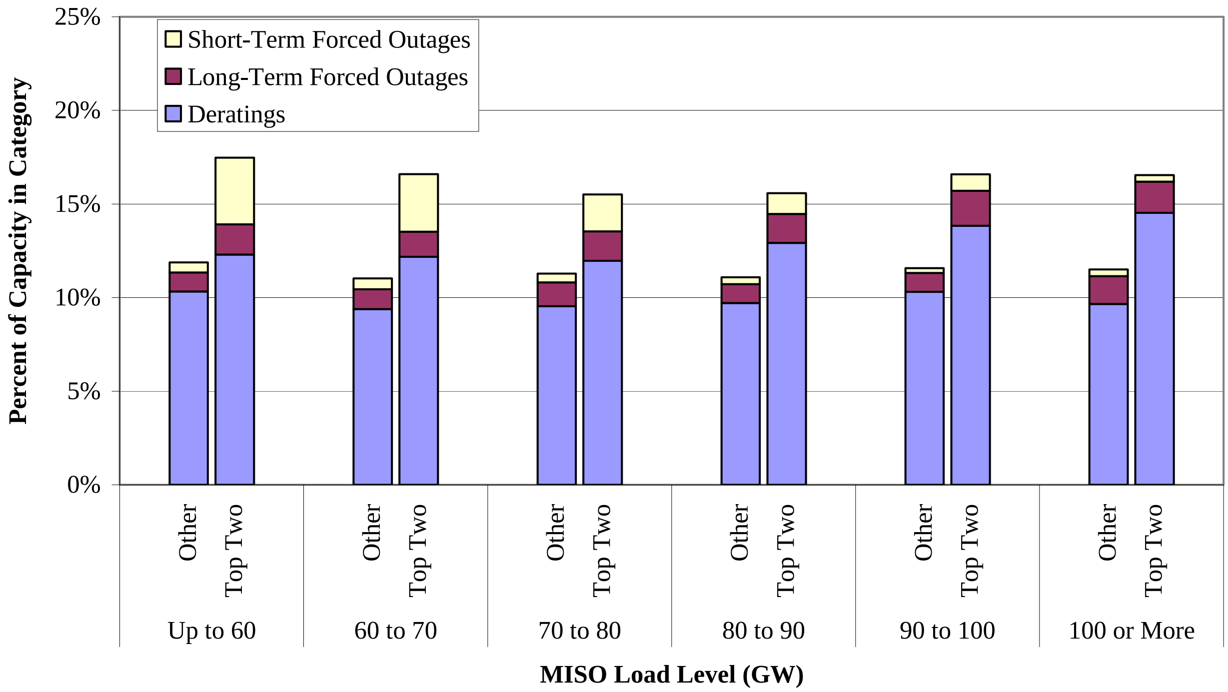
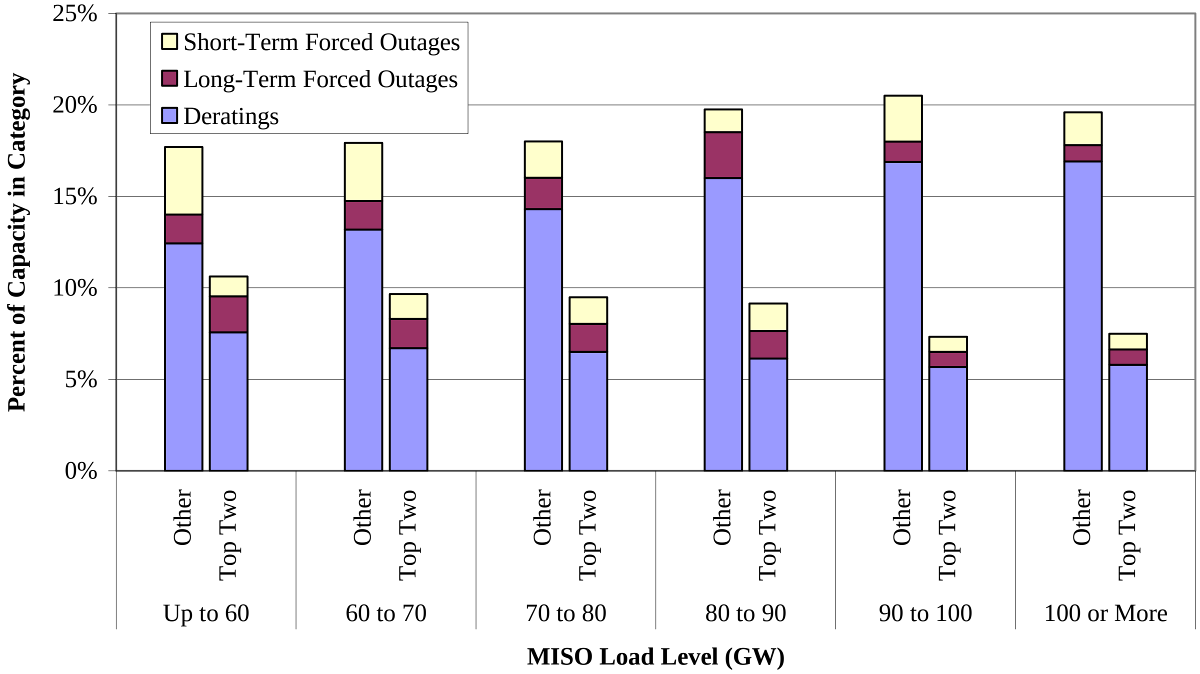


Figure 66: Real-Time Deratings and Forced Outages WUMS



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.

The results in these figures show that deratings and outages do not rise significantly under peak load conditions. We also observe that the quantities for the largest suppliers are generally lower than for other suppliers (ones that are less likely to have market power), with the exception of the results in the West region. Lastly, we separate short-term forced outages because they are the most likely to represent physical withholding. Taking a long-term forced outage of an economic unit is not likely to be as profitable as claiming a short-term forced outage because profits are likely to be lost for a long-term outage during hours when the supplier does not have market power. The figures show that short-term forced outage rates are generally lower for the largest suppliers than for other suppliers. In the West region, where the total outages and deratings of the large suppliers are relatively high, the short-term forced outages are particularly low during the peak hours.

Taken together, these results do not indicate that substantial patterns of physical withholding occurred during 2005. Nonetheless, as part of our market monitoring function, we investigate any outages or deratings that create substantial congestion or other price effects. These investigations confirmed the results shown above that physical withholding was not a concern in 2005.

C. Market Power Mitigation

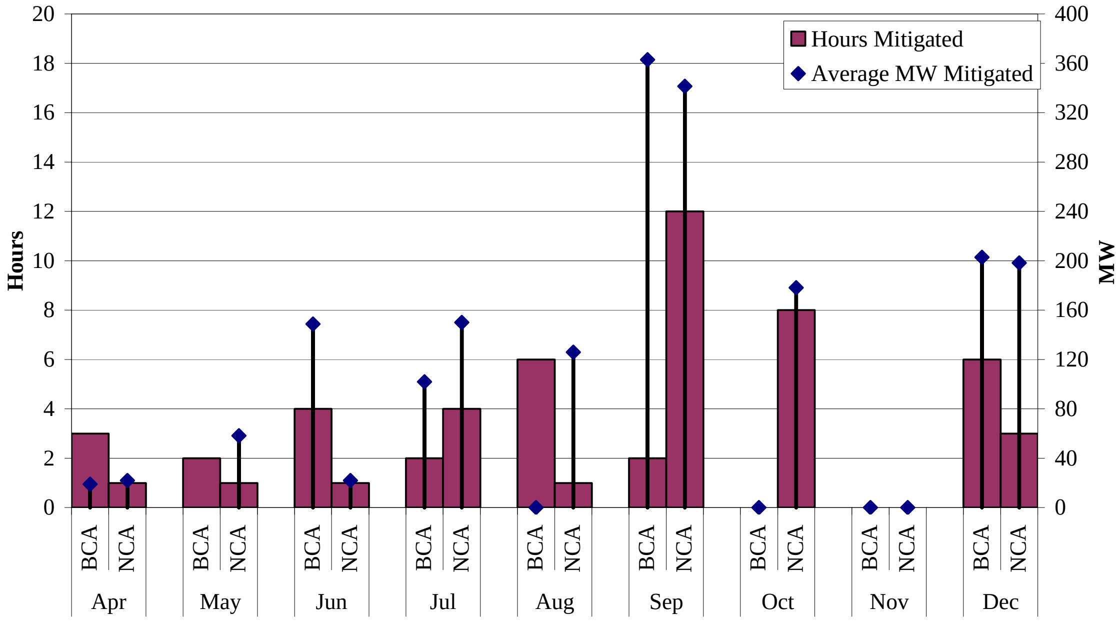
In this subsection, we describe and summarize the frequency with which market power mitigation measures have been imposed in the Midwest ISO markets. The mitigation measures are contained in Module D of the Midwest ISO tariff. They are intended to mitigate abuses of locational market power while minimizing 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 the 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 67 shows the frequency and quantity of mitigation in the real-time market by month.

Figure 67: Real-Time Mitigation by Month



The figure shows that NCA mitigation occurred less frequently than BCA mitigation in all but three months during the 9-month study period. However, both classes of mitigation were relatively infrequent. There were 24 BCA events and 62 NCA mitigation events. The most mitigation occurred in September with 14 hours of mitigation. Although mitigation was relatively infrequent in 2005, local market power remains a significant issue in the Midwest ISO region. In general, mitigation was infrequent because participants did not engage in significant economic or physical withholding, even when they had substantial local market power.

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. Figure 68 shows the frequency and amount by which RSG payments were mitigated in each month of 2005.

Figure 68: Real-Time RSG Mitigation by Month

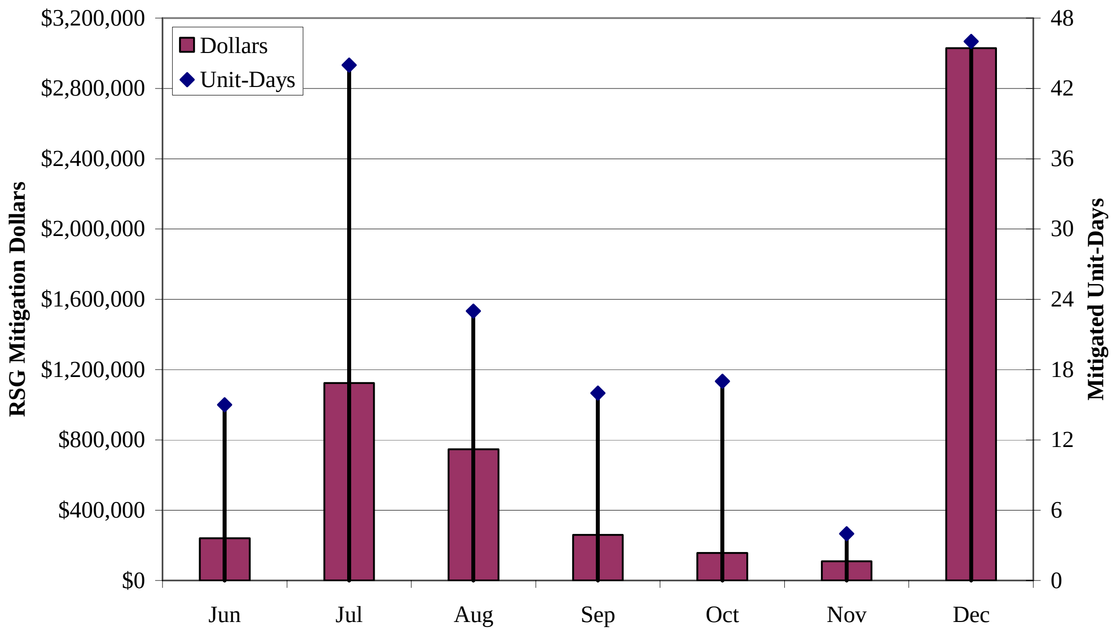


Figure 68 shows that only modest amounts of the total RSG payments were mitigated in most months. Both the frequency and magnitude of the RSG mitigation was highest in December 2005. More than $3 million of the RSG payment was mitigated in December. Mitigation occurred for 46 unit-days. Like the energy market, the modest levels of mitigation that occurred related to RSG payments was due to the fact that suppliers with local market power generally did not attempt to exercise market power.

In fact, we have estimated the Midwest ISO's exposure to higher RSG costs if participants with local market power in BCAs (i.e., those that are pivotal) were to have submitted $1 million dollar start-up and no-load offers in 2005. Actual real-time RSG costs exceeded $500 million in 2005. However, if pivotal suppliers in BCAs had engaged in the conduct described above, the additional RSG would have been almost $2.8 billion. We have reviewed these costs and can confirm that they are largely incurred when specific reliability issues arose in 2005 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.

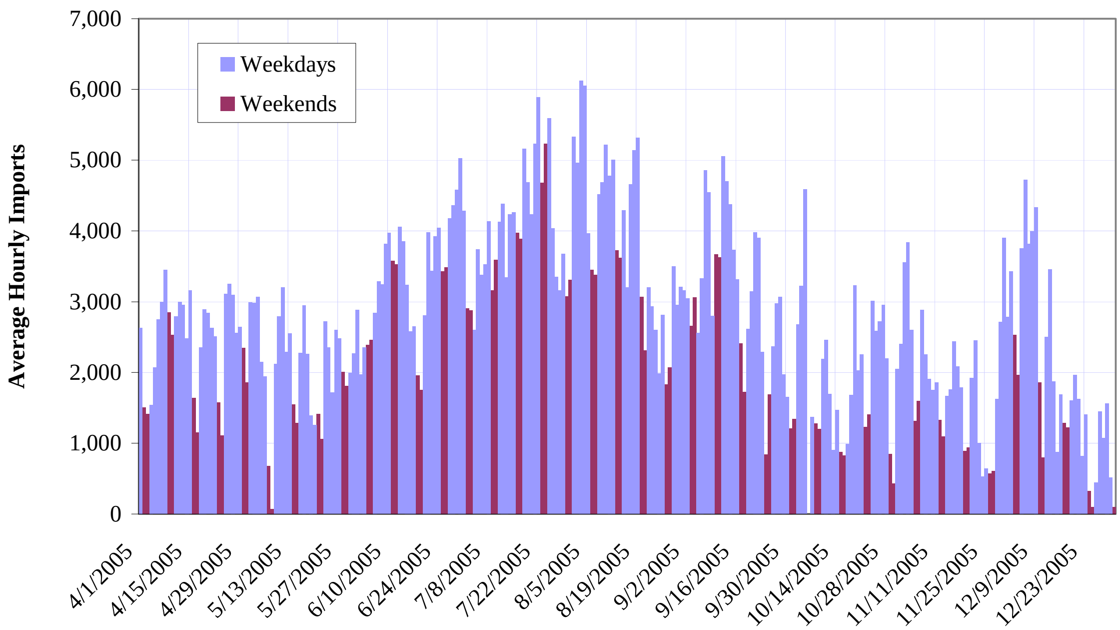
VII. External Transactions

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 the magnitude of the external transactions. Figure 69 shows the average hourly net imports scheduled in the day-ahead market on a daily basis.

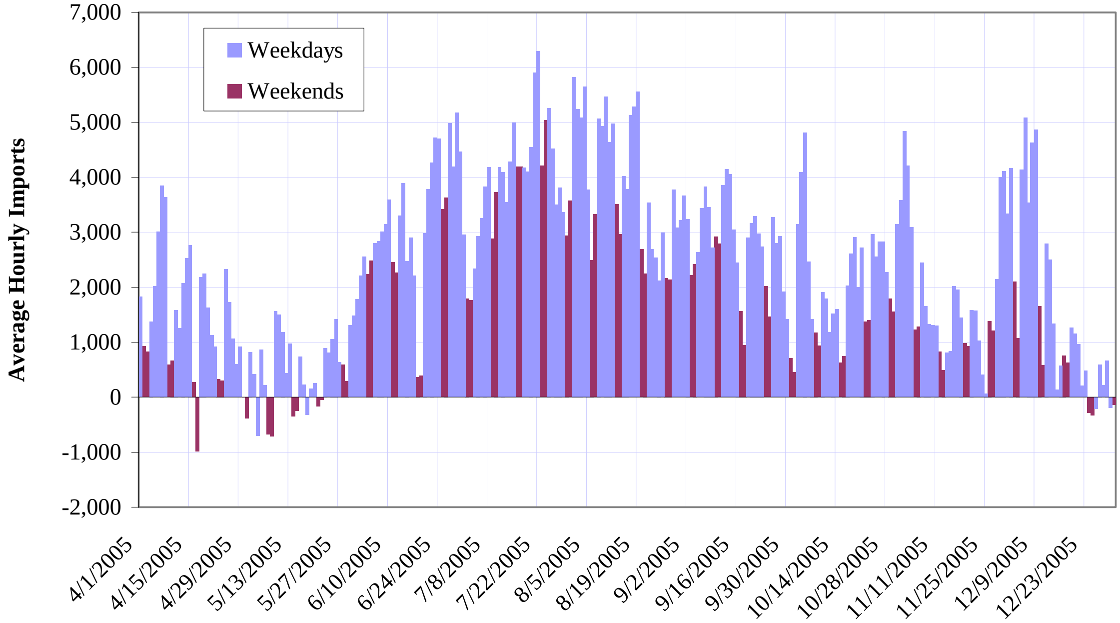
Figure 69: Average Hourly Day-Ahead Imports
All Hours



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. The level of net imports when the market began operation was initially below pre-market levels. However, the net imports increased rapidly to a maximum of more than 6100 MW on August 3. The pattern of net imports was seasonal with the largest imports occurring during the summer under the tightest market conditions. Net imports also rose sharply in late November, largely due to planned transmission and generation outages that led to very high prices in Minnesota.

The prior figure showed the net imports scheduled in the day-ahead market. It is important to recognize that the net imports in the real-time market can vary substantially from the levels scheduled in the day-ahead market. Figure 70 shows the average hourly net imports scheduled in the real-time market each day over all interfaces.

Figure 70: 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 3500 MW in on-peak hours and close to 2000 MW in off-peak hours. More than half of the net imports come from Manitoba. However, sizable differences in the net imports occurred in some hours, particularly in the early days of the market's operation. There were a number of days early in the market when the Midwest ISO became a net exporter of power in the real-time market even though it was a sizable net importer in the day-ahead market. Large changes in net imports from the day-ahead to the real-time market can cause the Midwest ISO to have to commit additional generation and to rely more heavily on peaking resources.

To better show where the Midwest imports and exports originate from, the following analysis show net imports by interface. Figure 71 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 Independent Electricity Market Operator of Ontario ("IMO"). The Midwest ISO is a net importer from MHEB through the high voltage DC connection, and a net exporter to IMO.

Figure 71: Hourly Average Real-Time Imports from Canada April through December 2005

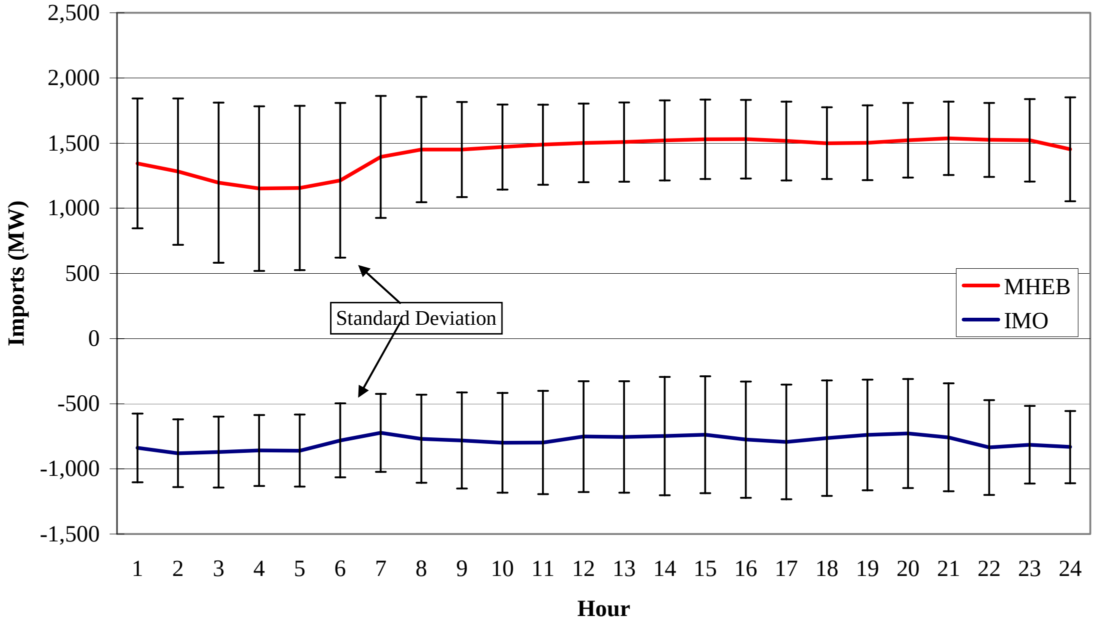
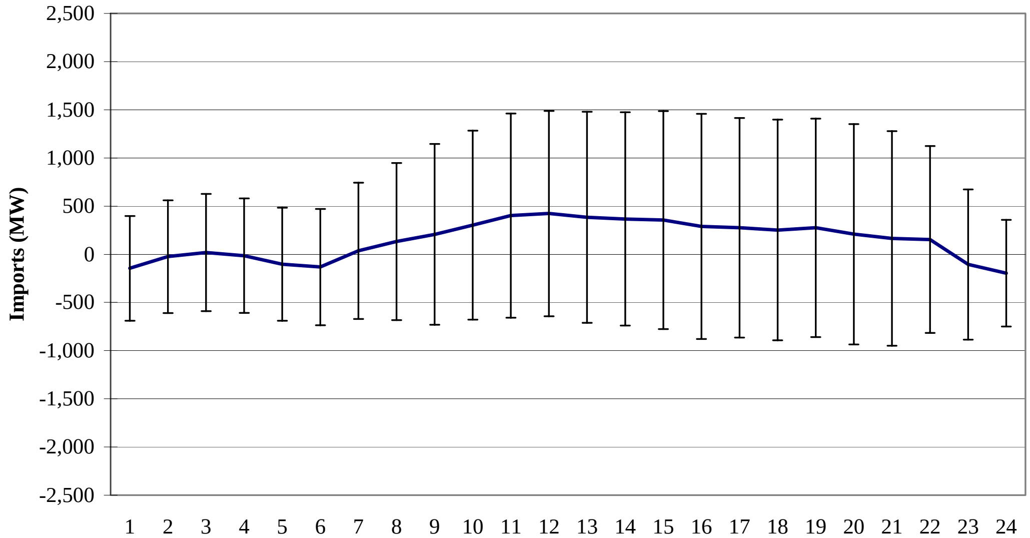


Figure 71 shows that the net imports from MHEB are generally higher in the peak hours and lower in the off-peak hours. The Midwest ISO is a net exporter to Ontario -- exports to IMO are generally lower in the peak hours and higher in the off-peak hours. This figure also shows the standard deviation of the net imports, which indicates that net imports from MHEB are much more variable in the off-peak hours overnight, likely caused by the relatively volatile prices in Minnesota in these hours. The standard deviation also indicates that net imports from MHEB in the peak hours are relatively stable.

One of the most significant interfaces is the one between the Midwest ISO and PJM, who both operate LMP markets over wide areas. Figure 72 shows the average net imports scheduled for the Midwest ISO-PJM interface for each hour of the day.

Figure 72: Hourly Average Real-Time Imports from PJM
April through December 2005



The Midwest ISO is a net importer of power from PJM overall. The figure shows that the Midwest ISO generally imports power during the peak hours of the day and exports power in the off-peak hours. However, the standard deviation of the net imports is large, particularly in the peak hours. This indicates that 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.

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 interfaces 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 73 and Figure 74.

Figure 73: Real-Time Prices and Interface Schedules PJM and the Midwest ISO

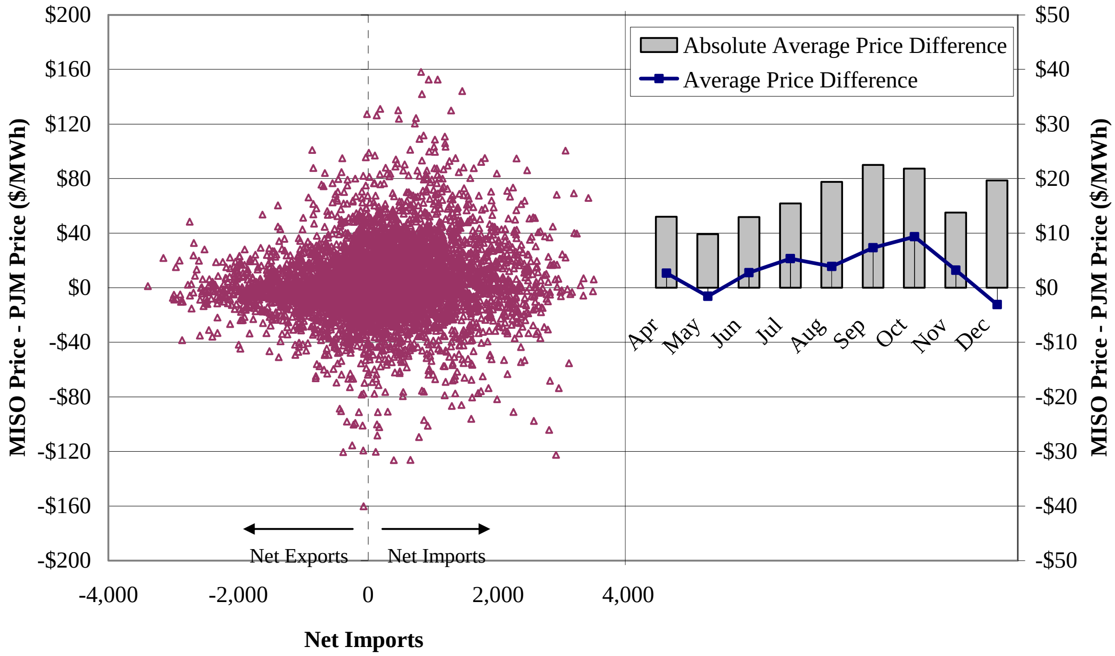
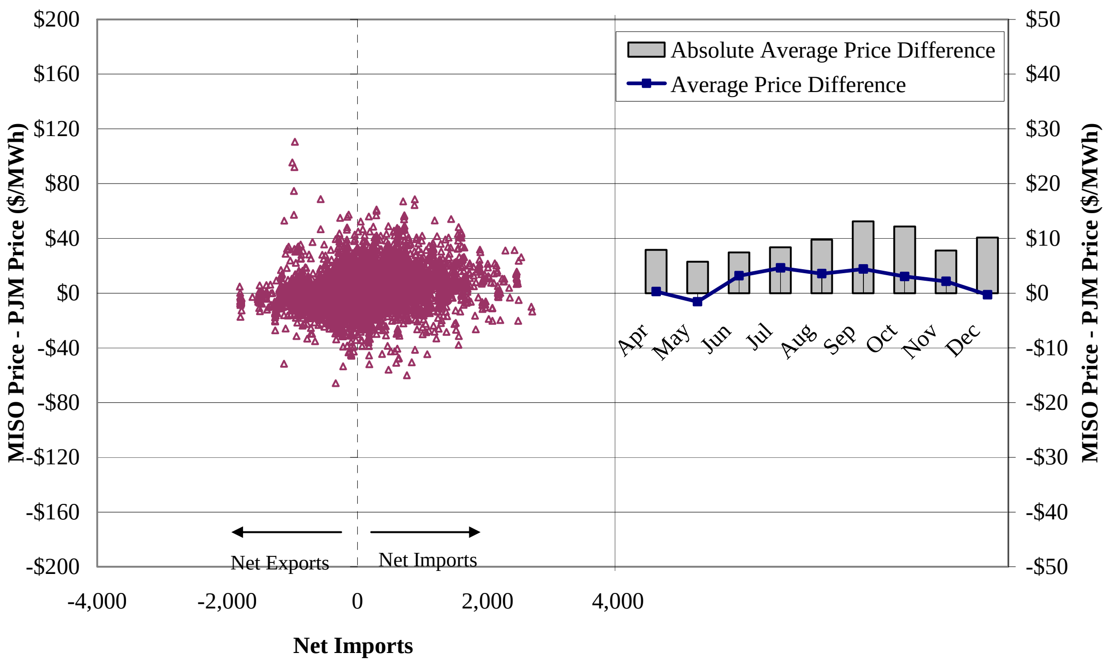


Figure 74: Day-Ahead Prices and Interface Schedules PJM and the Midwest ISO



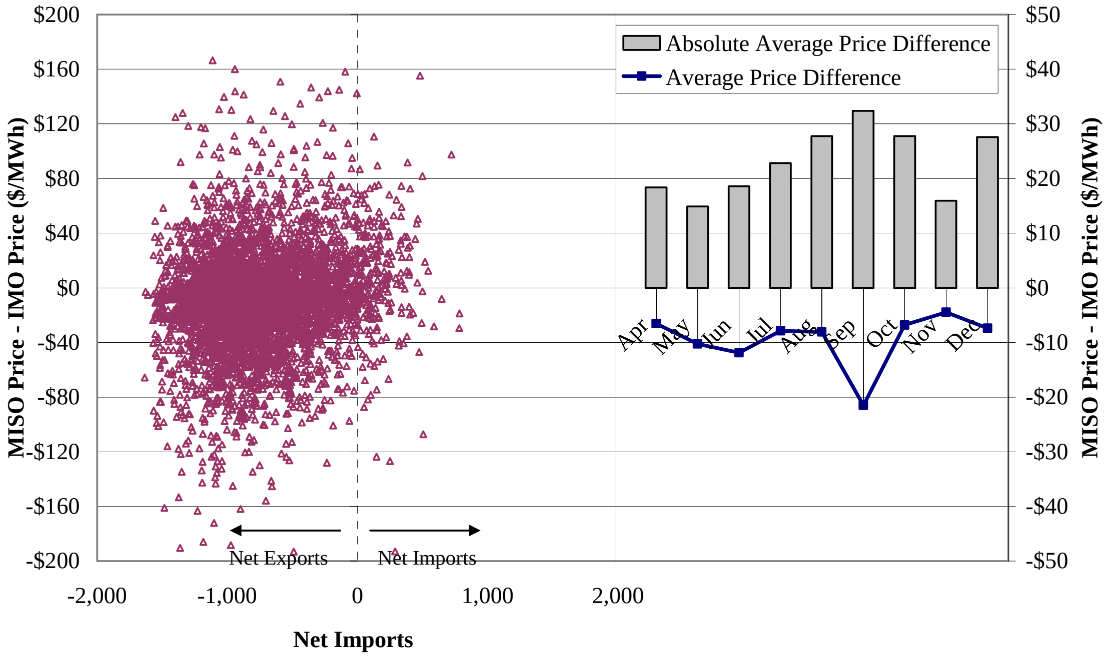
These figures indicate that the prices in the two areas are relatively well arbitraged in most hours. However, there are many hours when substantial price differences prevail. In a number of these hours, the power is flowing from the high-priced market to the lower-priced market (the upper left and lower 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' 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 as some would likely claim, it is simply dispatching the seam between the markets the same way the Midwest ISO manages flows over internal constraints – by accepting 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 75 provides the same analysis for the Midwest ISO – IMO interface.

Figure 75: Real-Time Prices and Interface Schedules IMO and the Midwest ISO



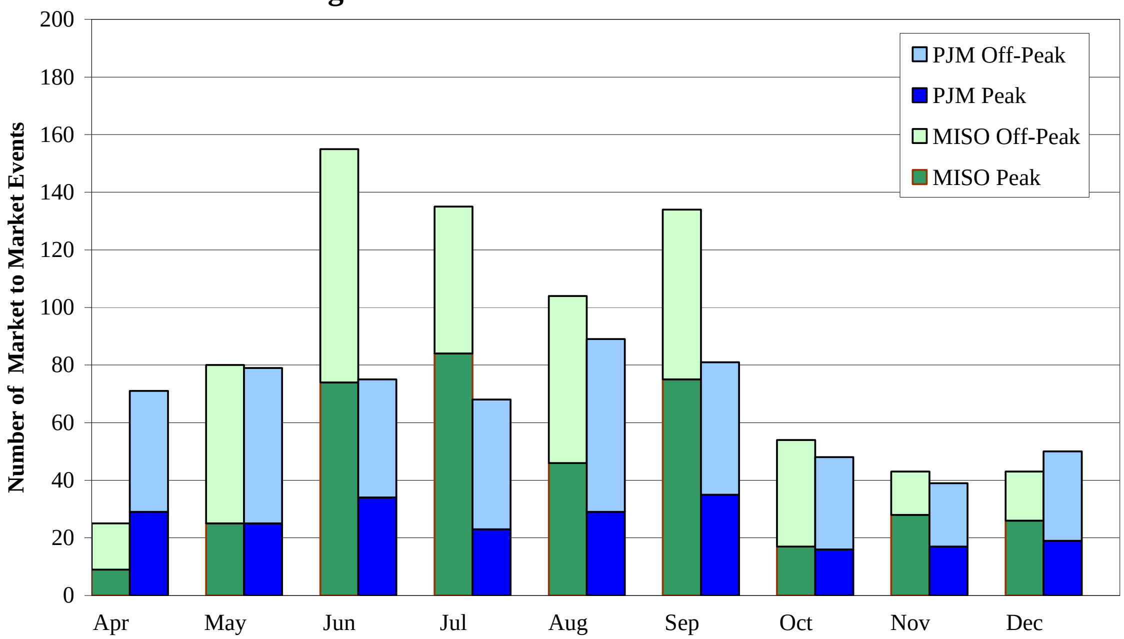
The Midwest ISO is a net exporter of power to IMO in virtually all hours. On average, the prices in the Midwest ISO are lower than the prices in IMO, which makes the net exports rational. However, there are many instances when the exports occur and the IMO prices are lower than the prices in the Midwest 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 IMO does not have a nodal market, so the IMO 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 that both systems impact (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 key for ensuring that generation is efficiently re-dispatched to manage these constraints and that prices in the two markets are consistent.

Figure 76 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.

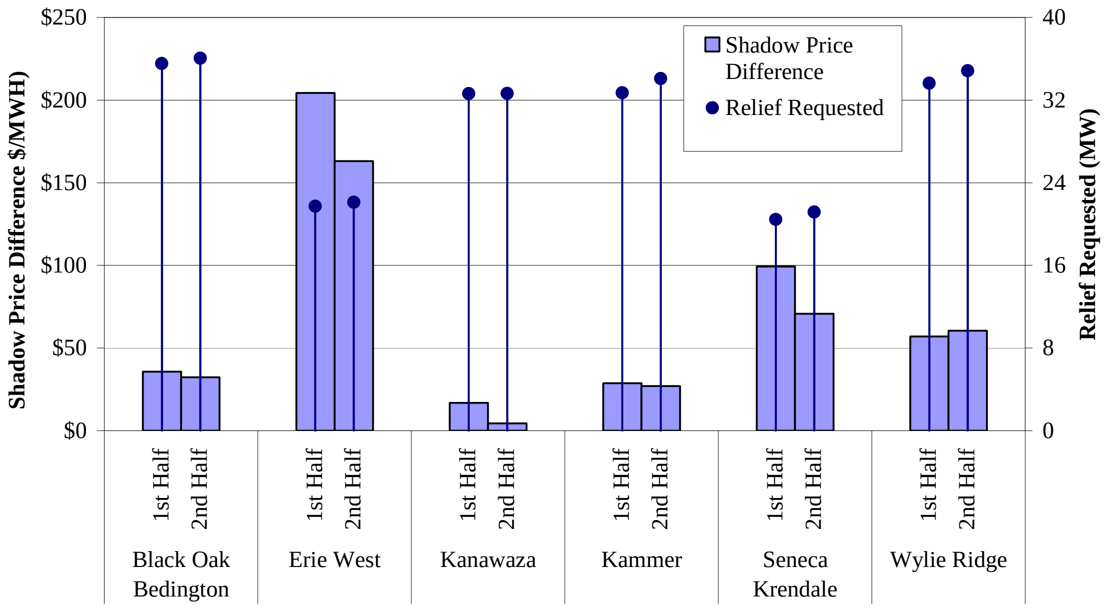
Figure 76: Market to Market Events



The figure shows that the market-to-market process has been used extensively to coordinate the relief of congestion on each system. The Midwest ISO market-to-market constraints have tended to occur seasonally (peaking in the summer) and are evenly divided between the peak and off-peak hours. PJM has activated market-to-market constraints slightly less frequently and they occur more frequently in off-peak hours.

To evaluate how well the market-to-market process has been working, the next two analyses evaluate differences in shadow prices and relief requested during market-to-market events. Figure 77 shows the most frequently called market-to-market constraints on the PJM system. This figure shows the average difference in shadow prices between the RTOs and the relief that was requested on average. For purposes of this figure, market-to-market constraints that are binding for at least 6 intervals (30 minutes) are analyzed to exclude very brief events. Each event is divided in half -- the average shadow price difference between the two systems and requested relief is shown for each half of the event.

Figure 77: PJM Market-to-Market Constraints Relief Requested and Shadow Prices



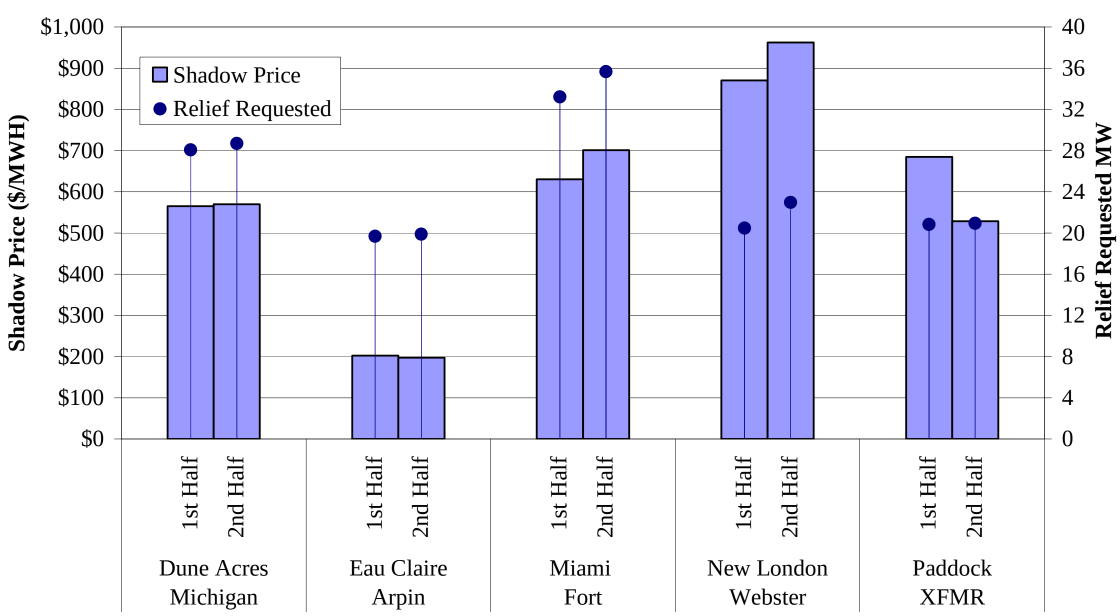
The figure shows that the shadow prices move toward convergence over the duration of the event, but good convergence is not always achieved for two reasons. First, the Midwest ISO frequently cannot provide the requested relief at a cost that is lower than the PJM shadow price. In these cases, the relaxation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

Our final analysis evaluates the Midwest ISO's market-to-market constraints. This analysis is very similar to the prior analysis of the PJM constraints. However, the PJM shadow prices for these constraints were not available for 2005 so we simply show the Midwest ISO shadow price rather than the difference between the two shadow prices as in the prior figure. Figure 78 shows our analysis for the five most frequently called market-to-market constraints on the Midwest ISO system. Eau Claire Arpin is the most frequently called market-to-market constraint by the Midwest ISO. In fact, it is called more frequently than all other Midwest ISO market-to-market constraints combined.

Figure 78: Midwest ISO Market-to-Market Constraints Relief Requested and Shadow Prices



This figure shows that the shadow prices do not decline substantially after the market-to-market constraint is activated. It also shows that, like the PJM constraints, the requested relief is relatively stable over the term of the events and the relief requested is frequently fairly low.

Like our recommendation for the PJM constraints, optimizing the quantity of relief that is requested would improve the operation of the market-to-market process.