2003 STATE OF THE MARKET REPORT

MIDWEST ISO

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Independent Market Monitor
for the Midwest ISO

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Executive Summary

This report evaluates the state of the Midwest ISO wholesale electricity markets in 2003. The Midwest ISO began operation in February 2002, implementing its open-access transmission tariff ("OATT"). In addition to administering its transmission tariff, the Midwest ISO was the reliability coordinator for the region and continued its preparations to introduce day-ahead and real-time energy markets in March 2005 ("Day-2 markets").

The Day-2 markets will dispatch generation to meet load and manage congestion at minimum production costs, based on the offers of each supplier. These markets will produce locational marginal prices ("LMPs") that will provide an efficient and transparent energy price for each location on the network, reflecting the costs of congestion and losses. Additional markets to be coordinated by the Midwest ISO, such as ancillary services markets or a resource adequacy market, may be implemented at a later date. The proposed tariff and market rules that will govern the Day-2 markets have been developed and were filed at FERC in March 2004.

Because the Midwest ISO does not operate centralized energy or ancillary services markets, the focus of this state-of-the market report is different than most other ISOs or RTOs. We review the outcomes in the bilateral markets during 2003, the supply and demand characteristics of the market, and a number of the Midwest ISO's current functions. The functions we review in this report are those that facilitate the wholesale market, including security coordination, AFC calculation, and tariff administration. The report also summarizes a market power analysis performed in anticipation of the Day-2 LMP markets. This executive summary provides a brief discussion of our findings and recommendations in each of these areas.

Market Characteristics

In analyzing the market characteristics of the Midwest ISO, we consider the Midwest ISO region to include both transmission-owning utilities that are presently Midwest ISO members as well as transmission-owning utilities that are anticipated to be Midwest ISO members by March 2005. We also include loads and resources that are directly connected to the Midwest ISO system and, therefore, must use the Midwest ISO Open Access Transmission Tariff.

The Midwest ISO "footprint" contains about 155,000 MW of generating capacity. Based on the summer peak load in 2003, the resource margin (defined as the percentage by which resources exceed peak load) in the Midwest ISO area is over 20 percent. To analyze the resource balance more closely, we divide the Midwest ISO into five sub-regions: ECAR, Iowa/MPS, MAPP (excluding Iowa), South MAIN, and WUMS. The designation of these sub-regions corresponds to major transmission areas studied in the MAIN Summer Transmission Assessment.[1]

The overall Midwest ISO resource margin remained essentially unchanged in 2003 because the increase in peak load was met by corresponding amounts of new generating and additional firm imports. In the five sub-regions, the resource margins range from 16 percent to percent 29 percent. The resource margin in MAPP is lower than in the other sub-regions. This does not raise significant concerns because it has adequate interconnections with neighboring areas. The WUMS resource margin in 2003 was close to 20 percent. However, the transmission capability from other regions is limited. Moreover, WUMS relies on substantial firm imports to meet its load requirements. These facts are consistent with the actual data on network congestion presented throughout this report, which shows that the transmission interfaces into the WUMS region are the most frequently congested in the region.

The generator fuel mix in the Midwest is dominated by coal-fired resources, accounting for almost 60 percent of the capability. Most of the recent investment has been in natural gas resources, which currently account for 16 percent of the capability in the region. Although natural gas-fired generation constitutes a relatively low share of the total generation in the Midwest ISO, it is the marginal source of supply and sets the market prices in the region in a disproportionately large percentage of hours. The Midwest

1 Coordinated 2003 Transmission System Assessment, MAIN, June 2003.

region relies very little on hydroelectric resources (less than 10 percent of the total capability) relative to other regions.

The concentration of the ownership of supply in the Midwest ISO region is very low. The Herfindahl-Hirschman Index ("HHI") used to measure market concentration is 261 for the Midwest ISO region, which is very low. The market concentration for the sub-regions is higher, although only the WUMS subregion is highly concentrated (an HHI higher than 1800) with an HHI statistic higher than 2600. These concentration statistics provide some useful information regarding the structure of the market. However, they do not provide a basis to draw reliable market power conclusions. The analysis described in Section VI of this report provides a more direct evaluation of potential market power in the Midwest ISO region.

With regard to load patterns during 2003, the report shows the sharp increase in load that occurs in the highest load hours. The peak hourly load in 2003 was 25 percent higher than the load level that defines the top five percent of the hourly loads. This characteristic of the hourly loads is typical and indicates the need in any electricity market for peaking resources. Given the need for operating reserves and the probability of forced outages, these load patterns mean that more than one third of the generating resources are needed only to provide operating reserves and to run to serve the load in less than 5 percent of the hours during the year. Hence, it is important for wholesale markets to price electricity efficiently in these hours so that peaking capacity will receive efficient price signals to guide investment decisions.

Wholesale Market Prices in 2003

The Midwest ISO wholesale electricity market is currently comprised only of bilateral trading. This report reviews the market outcomes in the Midwest by examining bilateral energy price data. This data shows that the average price in peak hours is more the twice as high as off-peak hours, and that the monthly average prices in July and August are among the highest of the year. These results show the expected correlation between electricity prices and load levels.

Our review of bilateral prices also shows a strong correlation between electricity prices and fuel prices, particularly natural gas. The highest monthly average prices in 2003 occurred in February and March, driven primarily by relatively high natural gas prices. Natural gas prices were 40 percent higher in these months than in July and August.

We also assessed how accurately the current wholesale prices reflected transmission congestion during 2003. The results of this analysis indicate that the current bilateral energy prices do not fully or accurately reflect the transmission congestion in the Midwest region. This conclusion supports the Midwest ISO's move to the Day-2 markets, which should provide more accurate and transparent price signals. These signals direct short-term generation commitment and dispatch decisions, as well as investment and retirement decisions. Hence, the Day-2 spot markets promise substantial efficiency benefits for the region in both the short-run and long-run.

Assessment of Transmission Service

Our analysis of requests for and approvals of transmission service indicates that transmission has generally been accessible in 2003, particularly short-term transmission service. The total numbers of requests approved and confirmed increased from 2002 to 2003 while approval rates have remained at high levels. As expected, approval rates for short-term service were greater than for long-term service and approval rates for non-firm service were greater than for firm service.

However, our analysis of long-term Available Transmission Capability ("ATC") shows little or no available capability on a number of key interfaces. Our review indicates that ATC may be understated due the process for allocating long-term transmission capability. The rules that tend to cause understated ATC include those that:

- Require flowgate capability to be reduced while a request is pending;
- Allow participants to submit multiple requests for the same service;
- Impose no cost for a participant that fails to confirm an approved transmission requests.

In addition, the volume of long-term requests on certain paths is relatively high, which is likely due to the pending elimination of the through-and-out charge for transmission to

PJM and the fact that newly acquired firm rights may create an entitlement for a participant to firm transmission rights under the Day 2 markets. Based on the analysis in this section of the report, we support the Midwest ISO's current process to consider options for improving the process for reserving long-term transmission service. Most of these options, such as charging a fee for reservation requests, should mitigate these issues and improve the availability of transmission service.

In a further assessment of transmission service, we examine the practice of "redirecting" transmission reservations (which allows a participant to designate alternative points of receipt and delivery for a firm reservation). The practice of redirecting transmission reservations can be beneficial because it increases the value of the transmission service for the participant and will generally lead to higher utilization of the transmission network. However, the current transmission revenue allocation rules can provide participants with the incentive to redirect unused firm service back to their own control area (or their affiliate's control area). This practice was not widespread during 2003. Nonetheless, the rules provide a competitive advantage to power marketers and other participants that are affiliated with a Midwest ISO transmission owner, and can allow them to hold firm capacity at very little cost. Therefore, we will continue to monitor this conduct and recommend that the Midwest ISO consider potential changes to the business practices to address the issue.

We also review the transmission reservation, confirmation, and approval process to investigate the practice of participants failing to confirm requests after they have been approved by the Midwest ISO. In selling transmission service, the Midwest ISO will reduce the available transmission capability associated with each reservation until it is refused or withdrawn. Hence, the capability needed to satisfy a request will be unavailable to other participants while the request is evaluated by the Midwest ISO and during the time allotted for the participant to confirm its request. While this time period after the approval can be valuable to a participant, who may need to arrange transmission service in an adjacent area to support a transaction, it also provides the participant a free option on the transmission capability during that time period and prevents others from reserving the service.

Our analysis in this report shows that there is little evidence that participants are using this process as a means to hoard transmission capability, i.e., to prevent their rivals from reserving the transmission service. Although we have not detected strategic conduct in this area, the quantities of unconfirmed requests have been significant. Hence, we recommend the Midwest ISO consider modifications in the AFC assumptions or the reservation process to mitigate effects of this conduct on the available transmission capability.

Midwest ISO Operations

The Midwest ISO manages transmission congestion through the NERC TLR Procedures.[2] Under these procedures, the Midwest ISO monitors real-time flowgates relative to their operating limits. When a flowgate exceeds its limit or is expected to exceed its limit (e.g. based on next hour scheduled transmission service, current hour ramping schedules, or other factors), security coordinators will take actions under these procedures to relieve line loadings.

The TLRs called on Midwest ISO flowgates (level 3 and above) accounted for 62 percent of all TLRs called in the Eastern Interconnect in 2003. The Midwest ISO's considerable share of total TLR events can be explained by the fact that much of the Eastern Interconnect is operated under LMP or other central markets that redispatch generation rather than utilizing TLR procedures to manage congestion.

TLR curtailment quantities have increased significantly from 2002, as has the number of TLR events. Most of the TLRs are called in three areas: WUMS, the Upper Peninsula of Michigan ("UPM"), and Iowa/MPS. A large share of the TLR events in WUMS and UPM correspond to congestion managed through cost-based redispatch by American Transmission Company. The primary cause of the high number of TLRs in the UPM, many of which resulted in firm curtailments, was an extended outage at the Presque Isle

2 See NERC Policy 9 and Appendices 9C1, "Transmission Loading Relief Procedure – Eastern Interconnection"; 9C1B, "Interchange Transaction Reallocation During TLR Levels 3a and 5a"; 9C1C, "Interchange Transaction Curtailments During TLR 3b"; and the "Parallel Flow Calculation Procedure Reference Document".

plant in the UPM. The TLR activity into the broader WUMS region was significantly higher in 2002 than 2003 due to transmission outages on the western interface into WUMS in 2002. Finally, one of the primary causes of the increased TLR activity in Iowa was the relatively light hydro conditions for Manitoba Hydro, which significantly affected the schedules and flows through the MAPP region.

In addition to reviewing the frequency and patterns of TLRs in the Midwest, we evaluated the Midwest ISO's TLR calls using actual flowgate flows and data on the curtailments called for by the ISO. These results indicate that the Midwest ISO invoked the TLR procedures in a consistent and justifiable manner. However, this does not imply that the TLR process is an efficient means to manage congestion.

To evaluate the efficiency of the TLR process, we estimated the redispatch of generation that would have been needed to achieve the same relief as was achieved by the TLR curtailments. This analysis reveals that the TLR process, on average, curtails more than three times the quantity of transactions as could be redispatched to achieve the same result. It also shows that for the individual flowgates, the TLR curtailments ranged from 73 percent more than the redispatch amount to 472 percent more (almost six times the redispatch amount). These results indicate that the TLR process is substantially inferior to a more discriminating approach to managing congestion, such as the Day 2 LMP markets. The Day 2 markets will result in substantial efficiency benefits by redispatching the most economic and effective resources to manage network congestion.

The final analysis evaluating the Midwest ISO's market operations focuses on periods when the Midwest ISO posted zero hourly non-firm Available Flowgate Capability ("AFC").[3] Hours with zero AFC are studied because they likely affect trading in the Midwest by causing short-term service requests to be refused, and by signaling to participants that capability is unavailable.

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3 ATC values correspond to the available capability between two locations (i.e., over a "contract path"). Alternatively, AFC values represent the capability available on a particular transmission facility or group of closely-related facilities. Hence, a limitation on one flowgate could limit the ATC value for many contract paths. Likewise, the reservation of service over a particular contract path will effectively use the AFC on many flowgates.

To assess the accuracy of the short-term AFC, we calculate the percentage of flowgate capability that is physically available in real time (accounting for Transmission Reliability Margin) during hours when the hourly non-firm AFC was posted as zero. There should be a close relationship between hourly non-firm AFC and the unused physical capability of a flowgate because non-firm AFC is calculated and posted close to the operating hour. In addition, non-firm service can be curtailed if necessary.

The AFC analysis indicates that in roughly half of the cases, the relevant flowgate has unused physical capability equal to more than 30 percent of the flowgates total capability. Based on these results, we recommend that the Midwest ISO expand their use of real-time state estimator information in the calculation of the hourly AFC values.

Market Power Analysis

In the final section of this report, we present the results of a market analysis that was conducted to evaluate locational market power issues in the Midwest ISO region. This analysis was first conducted in conjunction with the recent filing of the Midwest ISO Day-2 energy markets tariff. The market analysis identifies flowgates that are frequently congested and that may subject to locational market power. The analysis identifies suppliers that may be "pivotal" for a given constraint under certain market conditions. A pivotal supplier is one that is able to create or sustain congestion on a flowgate even when all other suppliers are dispatched for congestion relief.

We conducted the analysis on 121 flowgates that were congested during the past two years. To identify potential pivotal suppliers under a variety of conditions, we use four seasonal AFC to provide key inputs to the analysis (e.g., base generation, load, network flows). Of these flowgates, 51 had at least one pivotal supplier during one of the four seasonal cases evaluated. Twenty-eight of the 121 flowgates studied had more than one pivotal supplier in at least one of the monthly cases, while 19 of the flowgates had at least one pivotal supplier in all four cases.

The analysis also evaluates how much the pivotal suppliers would have to reduce their base output to cause the congestion. The results show that pivotal suppliers often do not need to reduce their overall output, which increases the market power concern.

Of the flowgates that exhibit one or more pivotal suppliers, generally only flowgates affecting flows into or within WUMS are frequently congested. Based on these results, we have designated WUMS and North WUMS as narrow constrained areas for purposes of the market power mitigation measures filed in March 2004. These proposed mitigation measures will effectively address the potential market power issues raised by this study.

I. Introduction

This report evaluates the state of the Midwest ISO wholesale electricity markets during 2003. The Midwest ISO wholesale markets continue to operate as bilateral contract markets while work to implement Day-2 LMP markets continued. The introduction of the Midwest ISO Day-2 LMP markets is planned for March 2005. The new markets will allow the Midwest ISO to efficiently manage transmission congestion and set transparent market-clearing prices at each location on the network.

Because the Midwest ISO does not operate centralized energy or ancillary services markets, the focus of this state-of-the market report is different than most other ISOs or RTOs that operate spot markets. We review the outcomes in the Midwest bilateral markets during 2003, the supply and demand characteristics of the region, and the Midwest ISO's current functions that facilitate the markets, which include security coordination, planning, and tariff administration. The report also summarizes a market power analysis performed in anticipation of the Day-2 LMP markets.

The central features of the Midwest ISO Day-2 LMP markets are day-ahead and real-time energy markets. Other centrally-coordinated markets, potentially including ancillary services markets and resource adequacy markets, may be implemented at a later date. The Day-2 markets will include the market power mitigation measures that address locational market power.

In addition to introducing LMP markets, the Midwest ISO and PJM continue to work to implement a Joint Operating Agreement ("JOA") that will allow them to coordinate their respective market operations. This coordination is particularly important when the Midwest ISO implements its Day-2 LMP markets in areas adjacent to PJM's LMP markets. The lack of effective coordination would likely lead to substantial inefficiencies and gaming opportunities. These issues were thoroughly analyzed in the Midwest ISO 2002 State of the Market Report and subsequent filings to the FERC.[4]

4 See 2002 State-of-the Market Report Midwest ISO; Affidavit of Dr. David B. Patton, American Electric Power Service Corp. et al., Docket Nos. ER03-262-000, et al.; Market Monitors'

The report is organized as follows. Section II contains an evaluation of the load and resource balance within the Midwest ISO, including the capacity to import and export power over the primary transmission interconnections in the Midwest. Section III presents a review and analysis of wholesale electricity prices in the Midwest, including an evaluation of how efficiently the current markets reflect network congestion. Section IV contains a summary and assessment of transmission reservation and scheduling patterns during 2003. Section V is an assessment of the Midwest ISO's current operations, including its management of congestion during 2003. Finally, Section VI summarizes a competitive analysis of the Midwest ISO region, focused primarily on locational market power that results from transmission network constraints.

Assessment of RTO Seams Issues in the Midwest, Midwest ISO Independent Transmission System Operator, Inc., Docket No. EL03-35-00.

II. Characteristics of Midwest Markets

Understanding the fundamental supply and demand conditions of the Midwest markets is important in assessing the current operations of the Midwest ISO, as well as for planning the March 2005 implementation of LMP energy markets. In this section of the report, we summarize load and generation within the Midwest ISO region and evaluate the resource balance in light of available transmission capability.

The Midwest ISO is the independent operator of a 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 include transmission systems of entities that are presently Midwest ISO members as well as entities anticipated to be members by March 2005. We divide the Midwest ISO into five sub-regions based on the study areas used in the MAIN 2003 Summer Transmission Assessment. These sub-regions are useful in utilizing the transmission assessment results in conjunction with the generation and load statistics in each area. These five sub-regions are:

(1) ECAR -- the transmission-owning utilities in the NERC ECAR region that are or are anticipated to be members of the Midwest ISO;

(2) Iowa/Missouri Public Service -- the Iowa utilities – MidAmerican, Alliant West, and Muscatine; and Missouri Public Service (including West Plains Energy);

(3) MAPP -- the transmission-owning utilities in the NERC MAPP region, (excluding those in Iowa/MPS but including Manitoba Hydro);

(4) South MAIN -- the transmission-owning utilities in the NERC MAIN region (excluding non-Midwest ISO members Commonwealth Edison and Illinois Power and excluding the WUMS utilities); and

(5) WUMS -- the transmission-owning utilities in the NERC MAIN region that are located in Wisconsin and Upper Michigan (excluding Northern States Power, which is included in MAPP).

In identifying load and resources within the Midwest ISO region, we consider all loads and resources that are dependent on the Midwest ISO transmission facilities. These include some generators and loads that are not Midwest ISO participants. For example, certain municipal systems may not be Midwest ISO signatories but must use the Midwest ISO transmission network and, thus, abide by its scheduling rules and take service under its tariff.

There are over 400 distinct owners of generation resources in the Midwest ISO, including 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 generations statistics in this section.

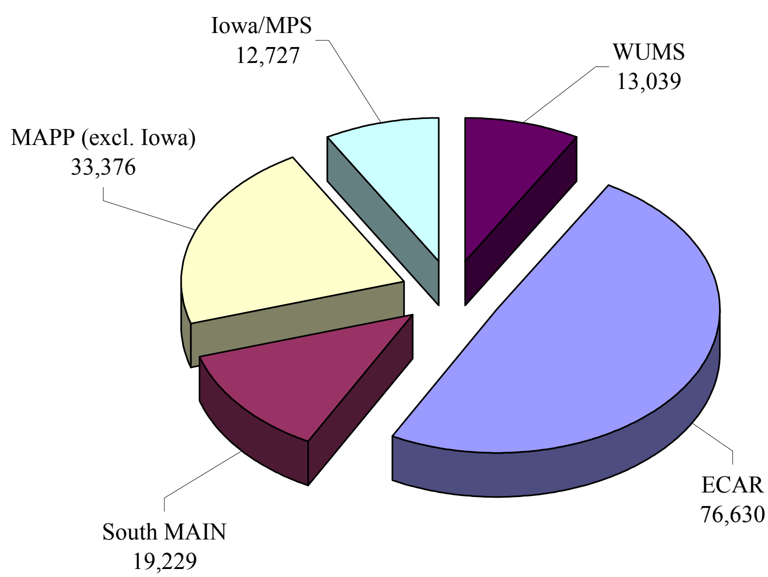
In the subsequent analyses using these Midwest ISO sub-regions, it should be emphasized that these individual areas should not be viewed as distinct geographic markets. This is particularly important for the data presented below concerning market concentration in these sub-regions. Therefore, the ownership of capacity within the sub-regions should not be a basis for a conclusion about market power. An accurate market power analysis would require substantially more investigation beyond simply calculating market shares and concentration statistics, such as the analysis in Section VI.

A. Supply and Demand Balance

In this subsection, we evaluate the supply and demand balance by identifying loads, generating resources, and firm transfers within the five Midwest ISO sub-regions. This provides the data for calculating each sub-region's "resource margin", the margin by which firm resources exceed annual peak demand. We find that resources in the Midwest ISO are generally adequate, although limited transfer capability in the WUMS sub-region raises some concerns.

Figure 1 shows the distribution of generating capacity within the five Midwest ISO sub-regions. For the Midwest ISO altogether, the generating resources total about 155,000 MW. The ECAR sub-region is the largest, with almost one-half of the total Midwest ISO capacity.

Figure 1: Geographic Distribution of Regional Generation Capacity



Note: South MAIN does not include Alliant West, which is included in Iowa/MPS.

The distribution of capacity shown in Figure 1 is better viewed in light of sub-regional load and firm transfers. Table 1 summarizes the generation and firm power transfers in each sub-region and shows the resource margin.

Table 1: Summary of Generation and Resource Margins 2003 Peak

	Generating Capacity	Net Firm Imports	Total Firm Resources	Resource Margin
ECAR	76,630	708	77,338	25.1%
South MAIN	19,229	(38)	19,191	28.0%
MAPP (Excl. Iowa)	33,376	(211)	33,165	16.1%
Iowa/MPS	12,727	1,041	13,768	26.7%
WUMS	13,039	1,679	14,718	19.8%
Total MISO	155,000	3,179	158,179	23.1%

Note: Peak loads used to calculate the Resource Margin were derived from Midwest ISO data. This was supplemented, when necessary, by data from Platts. Net Firm Imports were based on data from the MAIN Summer Assessment and the Main Load and Resource Audit, Summer 2003.

In the table, Total Firm Resources is the sum of Generating Capacity and Net Firm Imports. It does not include demand-side resources. 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 resource were available but not deployed during peak periods, the resource margins may be slightly underestimated because the peak load will be higher.

With the exceptions of MAPP and WUMS, Table 1 shows that the Midwest ISO sub-regions have substantial firm resources with resource margins generally ranging between 20 percent and 30 percent. While the MAPP resource margin is lower than the other sub-regions, it is adequately interconnected with Iowa and other regions. Taken together with Iowa, the resource margin is approximately 19 percent. The resource margin in WUMS is relatively low (although slightly higher than in 2002) and there is a heavy reliance on the transmission interfaces to import power from adjacent areas.

It is important to recognize that these resource margins are calculated somewhat differently than reserve margins. For example, as noted above, we did not attempt to quantify and include all sources of interruptible demand. Hence, demand that was actually interrupted during the system peak would be included while other interruptible demand would not be included. This is one of the reasons that our estimate of the resource margin in the WUMS area is slightly lower than comparable values cited elsewhere.

Table 2 summarizes the changes in loads and resources from 2002 to 2003. The table shows that peak load increased at about the same rate as total resources and, therefore, the overall resource margin increased only slightly (by 0.03 percent). New capacity that began operation during 2003 in the Midwest ISO region totaled approximately 3800 MW, while close to 600 MW were retired in 2002. Hence, generating capacity increased in 2003 by close to 3200 MW. Total resources also increased as a result of a larger volume of firm transfers into the Midwest ISO, mainly as a result of an increase in transfers from Illinois Power and Commonwealth Edison.

Table 2: Midwest ISO Generating Capacity 2002 - 2003

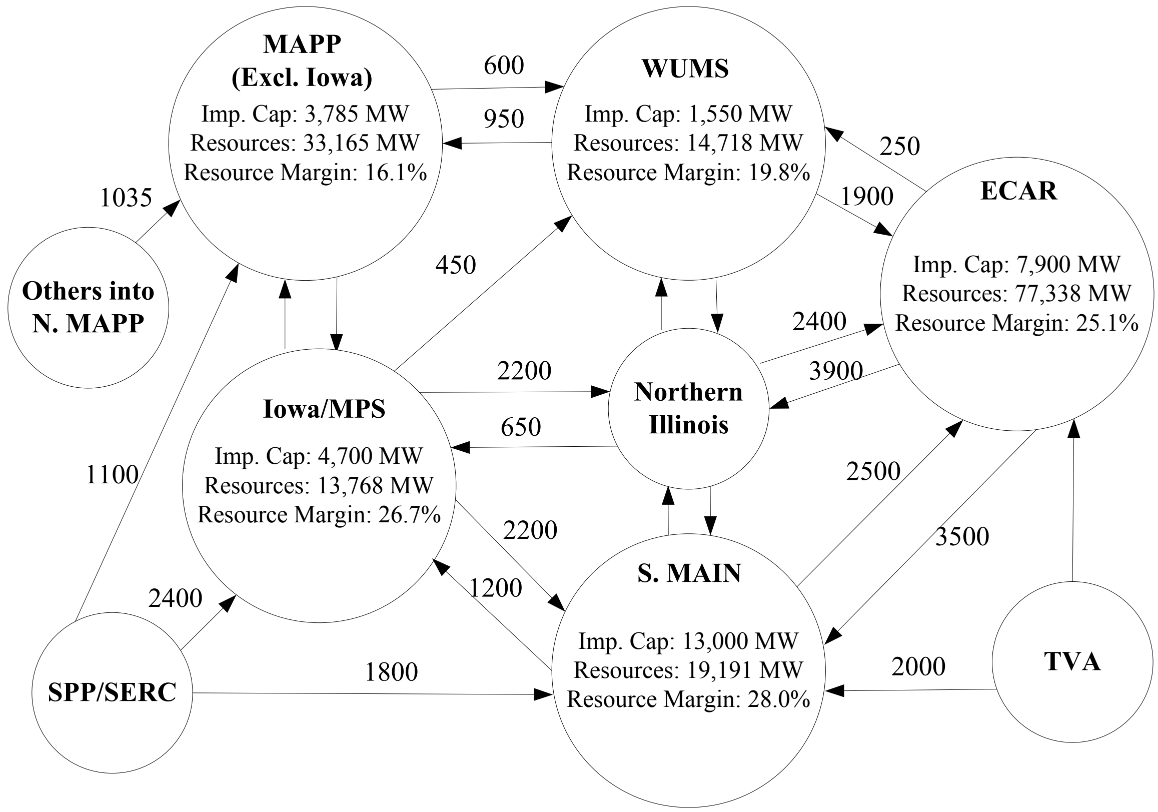
	2003	2002	*Net Change*
Total Resources (MW)	158,179	153,603	*3,154*
Load (MW)	128,526	124,726	*3,801*
Resource Margin	23.1%	23.2%	*-0.1%*

Note : Numbers may not add exactly due to rounding.

Figure 2 shows a graphical representation of the interconnections between Midwest ISO sub-regions and between the Midwest ISO and surrounding areas. Using data from the 2003 MAIN Summer Assessment, the diagram in Figure 2 shows the transfer capability, total generation, and the resource margin for each sub-region.

The transfer capability shown in this figure is non-simultaneous capability, which means that paths into area may not be used simultaneously. This means that capability shown on each path into an area cannot be aggregated to calculate the total amount of power that can be imported into the area simultaneously. The simultaneous capability can be significantly less than the non-simultaneous capability because when power is transferred over one path, some of the power will flow over the other paths into the area and, thus, reducing the available transfer capability over those paths.

Figure 2: Midwest ISO Transmission Interconnections and Resource Balance



Although the MAPP sub-region has a relatively low resource margin, that diagram shows that the sub-region has access to about 3800 MW of non-simultaneous transfer capability. WUMS has a relatively low resource margin and access to only about 1550 MW of non-simultaneous transfer capability. The other regions all have both higher resource margins and higher non-simultaneous transfer capabilities.

B. Midwest ISO Capacity Profile

In this section, we further examine the Midwest ISO generation capacity by showing the composition of generating capacity by fuel type. Figure 3 shows the total of each capacity type in each of the Midwest ISO sub-regions. Figure 4 presents the same data as percentage shares of the total capacity. This allows a more direct comparison of the mix of generation between sub-regions.

Figure 3: Capacity by Fuel Type in Midwest ISO Sub-Regions

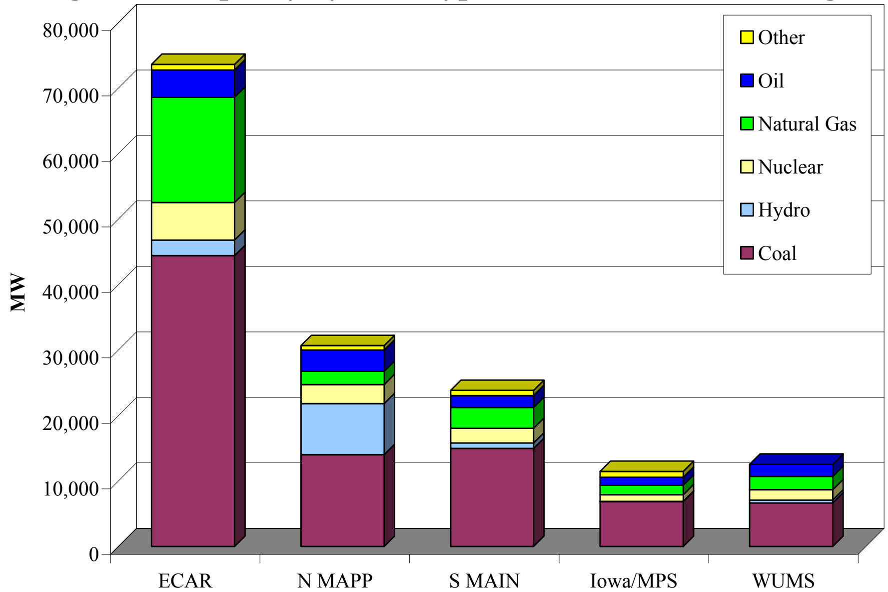
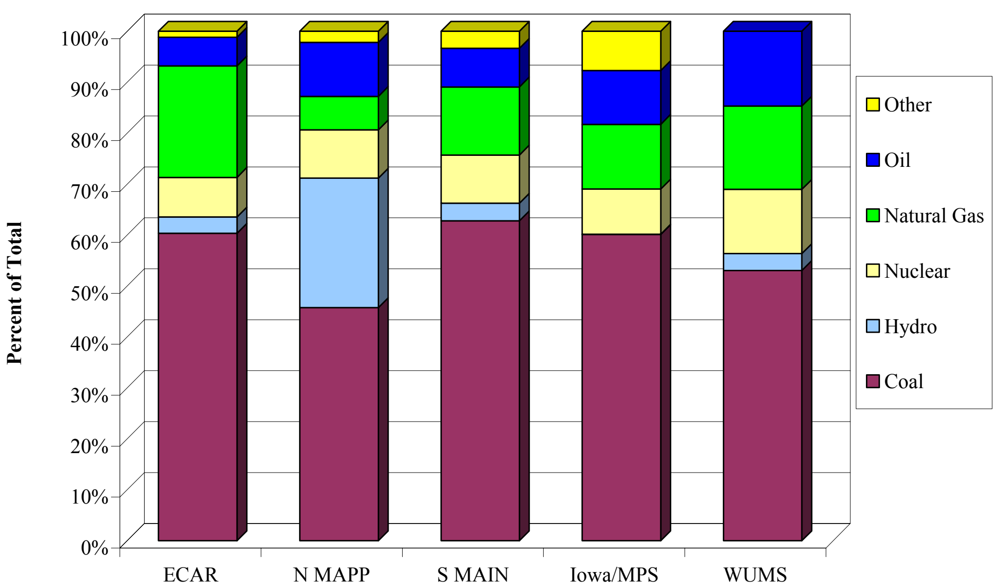


Figure 4: Capacity Shares by Fuel Type in Midwest ISO Sub-Regions



The figures show that the Midwest ISO and each of its sub-regions rely heavily on coal-fired generation, which represents almost 60 percent of the generation in the Midwest ISO region. Nuclear, oil-fired, and hydroelectric resources together represent almost 25 percent of the total resources. Natural gas-fired generating resources represent 16 percent of the supply in the Midwest, although this type of capacity accounts for most of the new capacity.

Figure 4 also reveals that Midwest ISO sub-regions are comparable in their generation mix, with the exception of MAPP. MAPP has somewhat more hydroelectric generation capacity and less natural gas and coal generation capacity than the other Midwest ISO sub-regions.

C. Market Concentration

As a final analysis of Midwest ISO generation capacity, we calculate ownership concentration. We use the Herfindahl-Hirschman Index ("HHI") to measure concentration. The HHI is calculated by summing the square of each participant's market share. This statistic is generally used by economists to assess the overall competitive structure of the market. The antitrust agencies (Department of Justice and the Federal Trade Commission) consider markets with HHIs exceeding 1800 to be highly concentrated and those with HHIs of less than 1000 as un-concentrated. HHIs in the range of 1000 to 1800 are considered to be moderately concentrated. The HHI is frequently used to evaluate the competitive impact of mergers by measuring the change in the HHI in the relevant market due to the merger.

The HHI is most useful when it is calculated for well-defined geographic and product markets. Geographic markets in the electricity industry are generally defined by physical transmission constraints that limit the extent of competition and are, therefore, dynamic in nature. The sub-regions of the Midwest ISO are not defined as geographic markets in this sense and, therefore, the HHIs calculated in each sub-region cannot support any competitive conclusions. In addition, the HHI's usefulness is limited by the fact that it reflects only the supply-side, ignoring demand-side factors that affect the competitiveness of the market.[5] Therefore, HHI statistics cannot be used to draw reliable market power

5 The most important demand-side factor is the level of peak demand. Markets with higher resource margins tend to be much more competitive, all other things equal.

inferences. Nonetheless, the market concentration within the Midwest ISO sub-regions can provide useful information and indicates areas of high concentration.

Table 3: Concentration in Midwest ISO Sub-Regions 2003

Midwest ISO Subregion	HHI
ECAR	563
MAPP (Excl. Iowa)	938
South MAIN	1,736
Iowa/MPS	1,343
WUMS	2,656
Midwest ISO	**261**

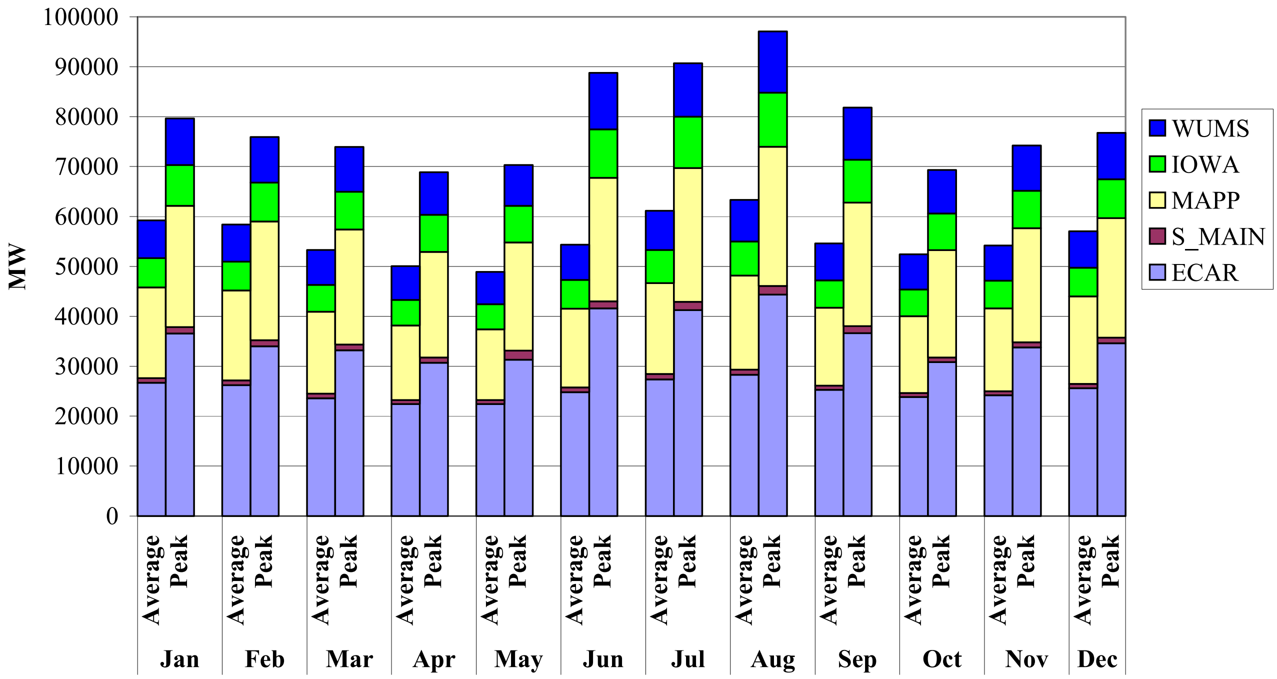
Table 3 summarizes the market concentration results, indicating that the South MAIN and IOWA/MPS sub-regions are only moderately concentrated and ECAR and MAPP are unconcentrated. The WUMS sub-region is exceptional in that it exhibits an HHI value in the highly-concentrated range. WUMS is the one sub-region that most closely reflects a geographic market, given the frequent congestion that occurs on the interfaces into that area. A detailed market power analysis is provided in the final section of this report, which provides a more accurate assessment of the competitive conditions in WUMS and elsewhere in the Midwest ISO.

D. Midwest ISO Load Patterns

The resource margins presented above are based on peak load and the total resources in each Midwest ISO sub-region. Peak load is important because it is central to the determination of the region's resource adequacy requirements. In this section, we analyze the load conditions in Midwest ISO region during 2003.

Figure 5 shows the average and peak loads in each sub-region by month. Due to the lack of available monthly load data for FirstEnergy, Ameren, Northern Indiana Public Service, and Montana-Dakota Utilities, these control areas are not included in the analysis. However, while excluding these entities affects the absolute level of load, it should not affect the overall load patterns.

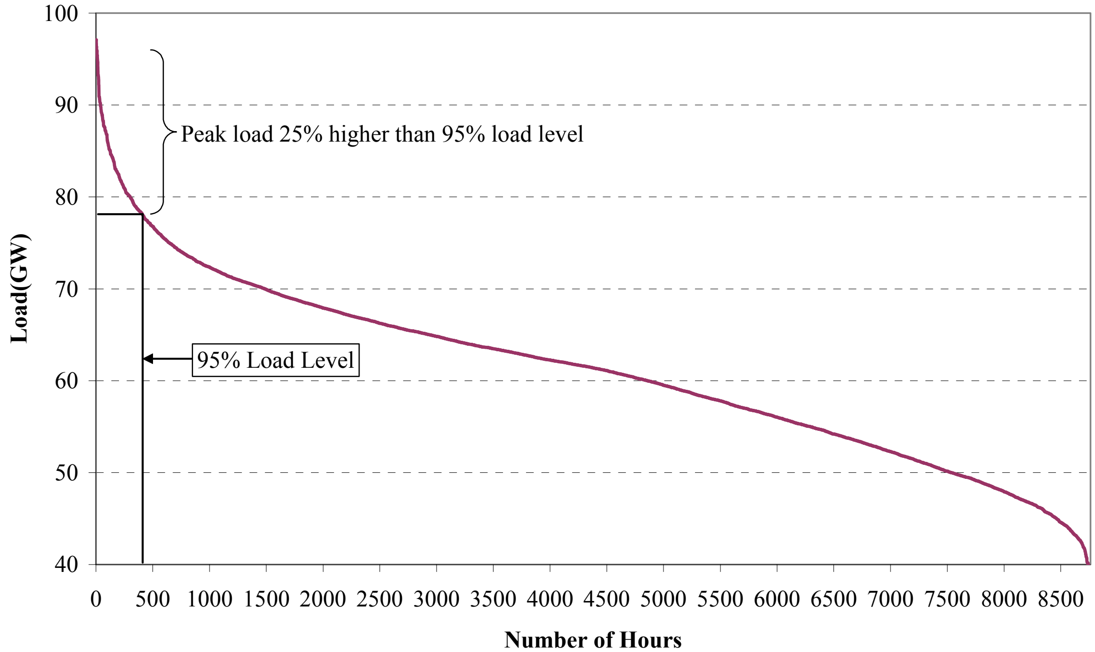
Figure 5: Monthly Average and Peak Loads 2003



As the figure shows, loads peaked for the year in August. There was a secondary winter peak in January. While some of the individual control areas experienced their peaks in the winter, all of the individual sub-regions have summer peaks. Like the generation shares shown in the prior sub-section, this figure shows that the largest share of the Midwest ISO's load is located in ECAR.

To examine the load levels on an hourly basis, Figure 6 shows a load duration curve for the Midwest ISO. The load duration curve shows the number of hours (on the ***x***-axis) in which the load exceeds a given load level (on the ***y***-axis).

Figure 6: Midwest ISO Load Duration Curve 2003



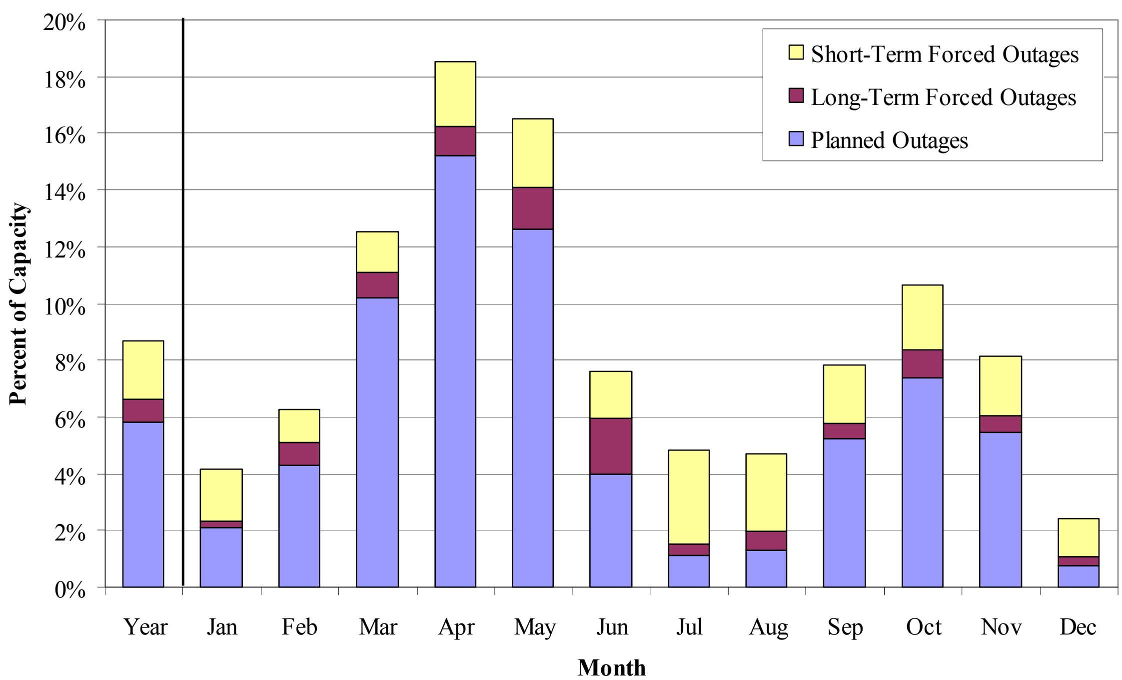
The load duration curve in Figure 6 exhibits the typical sharp peak demand, which is characteristic of electricity markets. The figure shows that peak load is 25 percent higher than the 95th percentile of load hours. This relationship illustrates the need in any electricity market for peaking resources. It indicates that about one-fourth of the generation can be expected to run in less than 5 percent of the hours. This highlights the critical need for wholesale markets to price electricity efficiently in these hours so that peaking capacity will receive efficient price signals to guide investment decisions.

E. Generator Outages

In this sub-section, we examine the generator outages that were reported to the Midwest ISO in 2003. Generator outages can be broadly classified as either planned or unplanned. Planned outages occur to accommodate routine maintenance or major capital improvements that are anticipated in advance. Planned outages are generally deferrable and are, therefore, typically undertaken during off-peak periods. Outages planned well in advance, such as those scheduled for annual maintenance are generally scheduled in the spring or fall. Shorter-term repairs or maintenance that arise during the year and can be deferred for short periods of time are generally scheduled at night or on weekends.

Unplanned or "forced" outages are usually the result of unexpected equipment failure or emergency maintenance requirements. Unplanned outages generally cannot be deferred, but there is normally time for a controlled shutdown. Figure 7 shows the monthly generator outages during 2003. These values include only full outages, no partial outages or deratings are included.

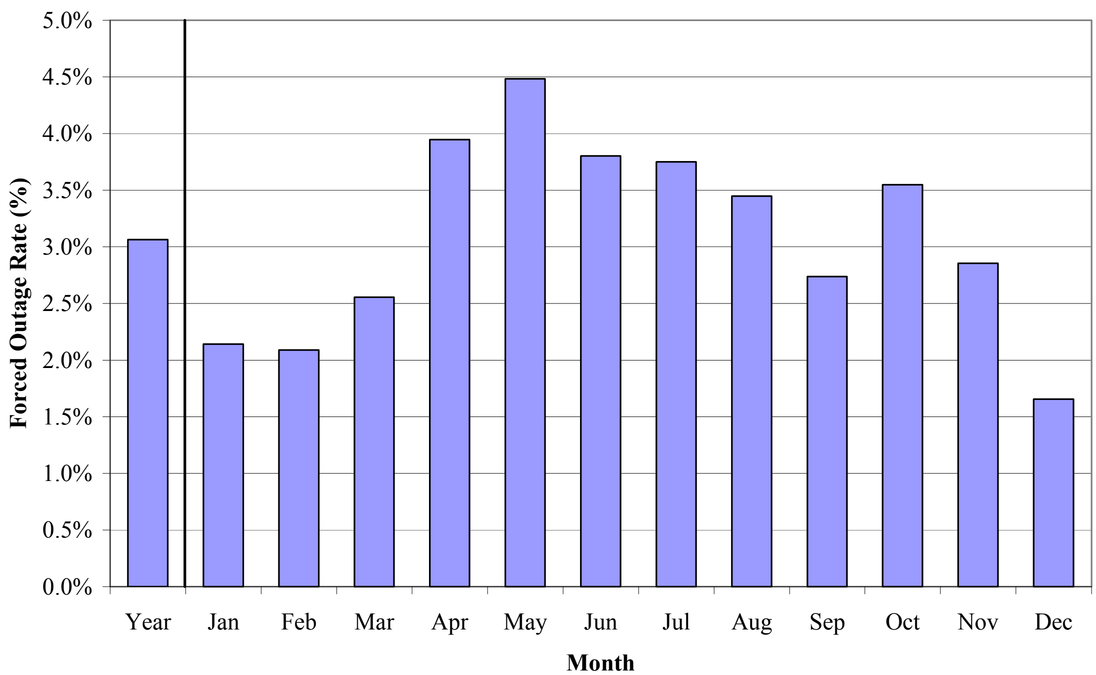
Figure 7: Generator Outages in 2003



The figure shows that generator outages were highest in spring and fall. Planned outages increased substantially in March to May as expected, peaking in April at more than 18 percent of all capacity. The figure also shows the division between short-term forced outages (less than 7 days) and long-term forced outages (longer than 7 days). The majority of the forced outages were short-term outages, particularly during the highest-load months of July and August. However, both the long-term and the short-term forced outages rates were very low.

To focus specifically on forced outages, Figure 8 shows the forced outage rates for Midwest ISO generators in each month in 2003 and the annual outage rate. The forced outage rate is calculated as the forced outage hours divided by the sum of the in-service hours and forced outage hours. Due to data limitations, we do not include forced partial outages. Hence, these rates cannot be compared to equivalent forced outage rates, which include the effects of partial outages.

Figure 8: Forced Outage Rates in 2003



This figure shows that the annual forced outage rate is slightly more than 3 percent, which is low relative to the forced outage rates in other regions. Furthermore, the forced outage rates remained low during the peak summer months. Based on our monitoring of forced outages, we find that they occurred randomly in 2003 as expected and provide little evidence of physical withholding of resources.

The extraordinarily low forced outage rates suggest that all outages may not have been reported to the Midwest ISO, despite market participant's obligation to report outages under the Midwest ISO Business Practice Manual. There are no sanctions for non-compliance with the Business Practice Manual's reporting requirements. Hence, the incentive to fully report all forced outages is relatively low, which could contribute to under-reporting of forced outages. As the Midwest ISO becomes increasingly responsible for generator commitment and dispatch under the Day-2 LMP markets, it is important that forced outages be fully and accurately reported.

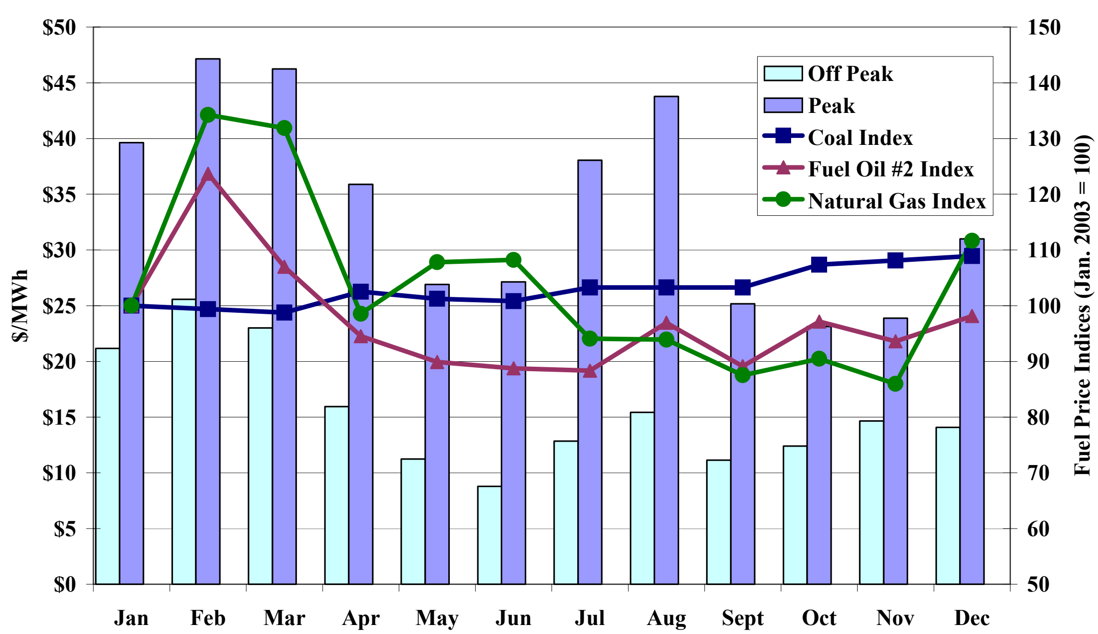
III. Wholesale Electricity Prices in 2003

Until the Day-2 LMP markets are implemented, the Midwest ISO wholesale market will be comprised only of bilateral trading. The analysis in this section evaluates the price trends in short-term bilateral transactions in 2003. We rely mainly on bilateral trading data that is collected through survey by private services. One such service is the Megawatt Daily survey, published by Platts. In this section, we use the Megawatt Daily volume-weighted average prices associated with day-ahead forward contracts and comparable price data from the Intercontinental Exchange ("ICE").

A. Summary of Price Trends

The first analysis in this section summarizes the daily electricity prices during 2003. Figure 9 shows monthly average prices at the Cinergy hub during peak and off-peak periods represented as side-by-side bars. The figure also shows price indices for coal, fuel oil, and natural gas. The fuel indices provide a reference to underlying input costs.

Figure 9: Monthly Average Electricity and Fuel Prices in 2003
Cinergy Day-Ahead Electricity Prices



Source: Electricity prices are reported in Megawatt Daily, published by Platts. Fuel Price indices are obtained from surveys published by Platts, including Gas Daily and Coal Outlook.

As one would expect, Figure 9 shows that prices are substantially higher during peak hours compared to off-peak hours. Likewise, prices during the summer months are higher than prices during the spring and fall months. These results show the importance of electricity demand in the determination of electricity prices. Because electricity cannot be stored economically, higher cost resources must be utilized in hours with higher demand, resulting in higher electricity prices in these hours.

The figure also shows that natural gas prices were a key driver of peak prices, and of off-peak prices in the winter months to a lesser extent. The increase in natural gas prices caused the highest monthly average electricity prices to occur in February and March. Although natural gas-fired generating units constitute only 16 percent of the total generating capacity in the Midwest ISO region, they are the marginal source of generation in a large share of the peak hours. The data shows that these units are also marginal in a significant number of off-peak hours during the winter. This is likely due to relatively high heating load that can occur at night during the winter when temperatures are the lowest.

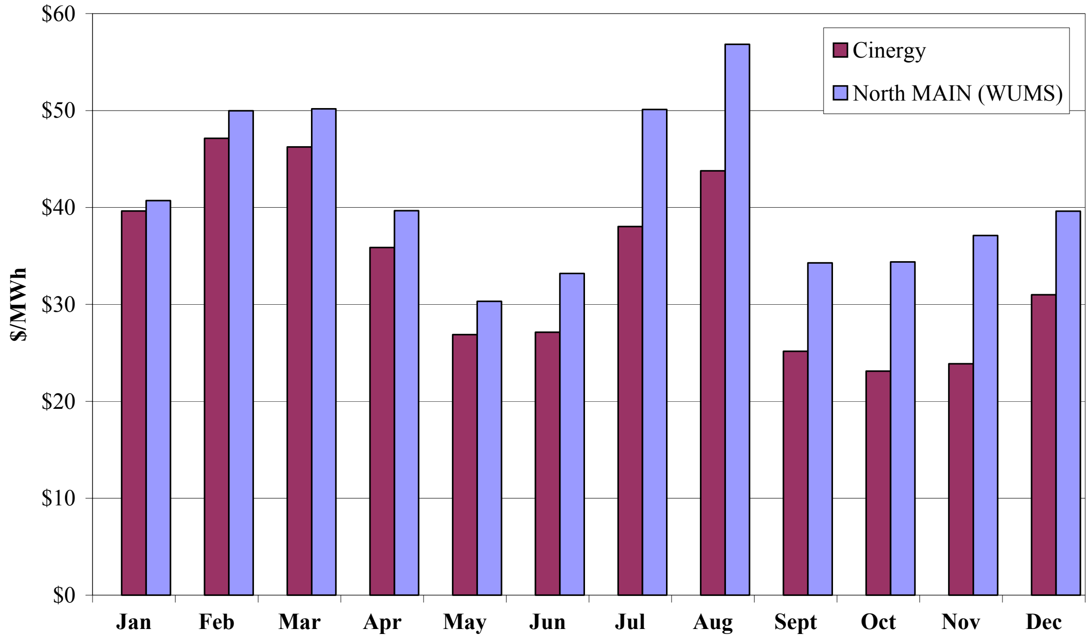
B. Inter-regional Price Differences

Figure 10 shows the daily average prices during peak hours at the Cinergy hub and in North MAIN. The Cinergy hub is shown because it is the most liquid trading point in the Midwest. The North MAIN pricing point is shown because it corresponds to the frequently-congested WUMS sub-region.

When constraints into WUMS are not binding, the prices inside and outside of WUMS should be comparable -- significant price differences would create obvious arbitrage opportunities. When these constraints are binding and re-dispatch of generation within WUMS is required to manage the constraint, the prices within WUMS should be higher to reflect the marginal cost of the required redispatch.[6]

[6] One caveat for the analysis in this section is that the price data often is based on very low trading volumes. On many days, no trading volume is reported. In these cases, Megawatt Daily publishes an indicative price based on available trade information, including bids and offers for energy.

Figure 10: Day-Ahead Electricity Prices in 2003
Monthly Average for Peak Hours
Cinergy and North MAIN



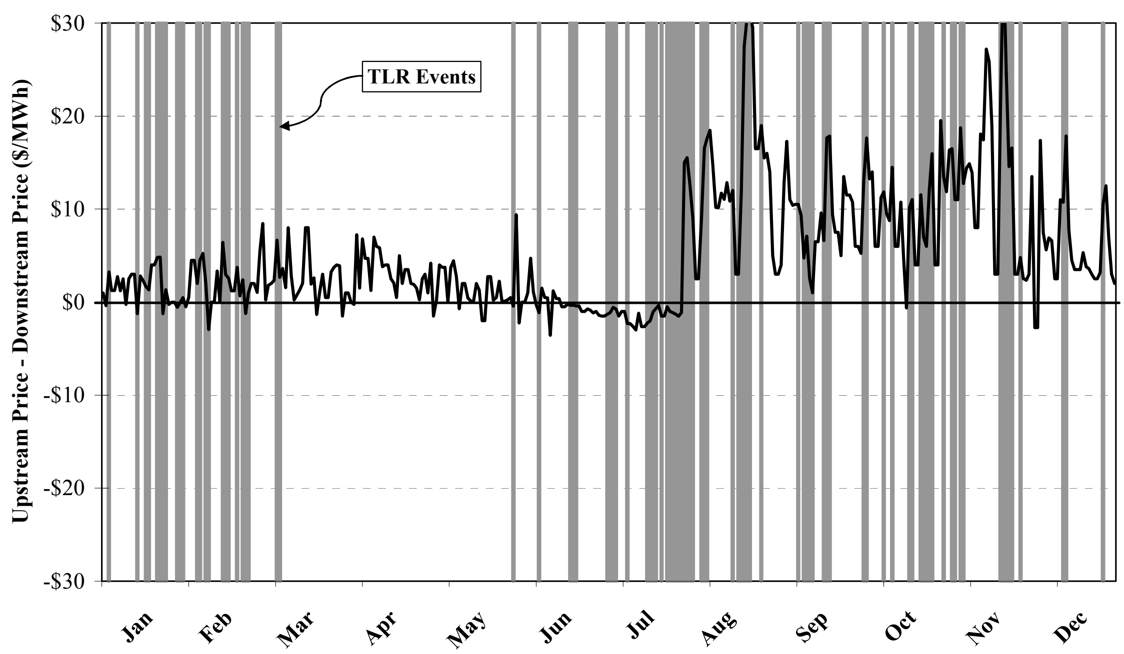
The figure shows that the average prices in North MAIN were higher than prices at the Cinergy hub in every month. In general, this is consistent with the pattern of congestion in the Midwest. The figure also shows that this difference became much larger in the second half of the year.

When transmission congestion arises as a result of binding transmission constraints, additional power is prevented from flowing into the constrained area and the price in the constrained area ("downstream price") should rise relative to the price outside of the constrained area ("upstream price). The following analysis investigates whether these pricing relationships exist under the current bilateral wholesale markets in the Midwest.

When transmission constraints arise on a flowgate under the current Midwest ISO congestion management system, the power flows are managed using TLR procedures. A TLR event of level 3 or higher results in transactions being curtailed or generation being dispatched to manage the flowgate. Therefore, an hour when a TLR event is in effect on a flowgate is indicative of a binding constraint. In our next analysis, we compute the difference between the downstream price and upstream price associated with a particular flowgate and determine how these prices differ when the flowgate constraint is binding.

The WUMS area represents the most frequently congested region in the Midwest and is, therefore, the focus of this analysis. Figure 11 shows the daily price difference between North MAIN (the downstream market), which represent WUMS, and Commonwealth Edison (the upstream market). The figure also includes shaded areas that are the TLR events on transmission flowgates that affect flows into the WUMS area.

Figure 11: Relationship of Downstream -- Upstream Prices during TLR Events
WUMS Flowgates -- 2003



Consistent with the discussion above, the downstream – upstream price difference should be positive when the flowgate constraint is binding. The figure shows that, indeed, some of the positive price differences coincide with the TLR events called on the WUMS flowgates. It is unclear from the figure whether the figure shows that TLR events are a significant determinant of the upstream to downstream price difference. To evaluate this question, we have conducted a statistical analysis of this data.

We conduct two statistical tests designed to evaluate the relationship between upstream and downstream prices. In our first analysis, we test whether the mean downstream-upstream price is statistically different in days with TLR events versus all other days. The analysis is conducted on each WUMS flowgate.

The analysis compares the peak prices for the day following the TLR event (prices associated with transactions initiated on the day with the TLR event) with prices on days without TLR events. We perform the same analysis on the prices for the day of the TLR event and the results were comparable. The results of the analysis are shown in Table 4.

Table 4: Effects of TLR Events on Energy Prices
Downstream – Upstream Price Basis

	Without TLR		With TLR		Difference	
Flowgate Name	**N**	**Mean**	**N**	**Mean**	**of Means**	**P-Value**
Paddock Xfmr 1 + Paddock-Rockdale	324	-0.054	35	0.503	-0.557	0.594
Russel-Rockdale 138/Paddock-Rockdale 345	355	0.020	4	-1.79	1.810	0.391
Albers-Paris138 for Wemp-Padock 345	307	0.014	52	-0.0854	0.099	0.911
Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	306	-0.062	53	0.365	-0.427	0.713
Lore-Turkey River 161 (flo) Wempletown-Paddock 345	331	-0.384	28	-2.3332	1.949	0.184
Salem 345/161 Quad Cities-Sub 91	343	-0.017	16	0.344	-0.361	0.839
Arnold-Vinton 161 for D.Arnold-Hazleton 345	313	-0.070	46	0.482	-0.552	0.572
Salem 345/161 flo Wempletown-Paddock 345	341	0.044	18	-0.8167	0.861	0.691
MHEX_N	310	0.023	49	-0.1416	0.165	0.847

The table shows the number of days in each category (i.e., with TLRs vs. without TLRs), the mean downstream-upstream price difference for each category, and the difference in these means. The "p-value" indicates whether the difference in the two means is statistically different from zero.[7] Economists generally employ a 95 percent confidence interval to determine whether a result is statistically significant, corresponding to a p-value that is less than 0.05. Hence, a p-value equal to or less than 0.05 indicates a statistically significant result.

7 The method of calculating the p-value depends upon whether the variances of the two samples are equal. When an additional statistical test indicates the variances are equal at the 95 percent confidence level, p-values are derived using the equal variance approach. Otherwise, p-values are derived using the unequal variance approach.

The results in Table 4 show that for none of the flowgates is the difference in the means statistically different from zero. Hence, no apparent relationship exists between the day-ahead bilateral market prices and transmission congestion. This is in contrast to what would be expected in a well-functioning market where price differences should be affected by congestion.

The second analysis examines whether the difference in the means increases or decreases significantly when a TLR is invoked. This is done by determining whether the mean of the downstream-upstream price difference for the day following the TLR event (associated with transactions initiated on the day with the TLR event) is significantly different than the mean of the difference for the previous day. The hypothesis in this case is that the downstream-upstream price difference should become more positive when the TLR event occurs. Table 5 shows the results for this analysis.

Table 5: Effects of TLR Events on the Change Energy Price Basis

Flowgate	Flowgate ID	Count - No TLR	Count - TLR	Est. Change ($/MWh)	P-value
Paddock Xfmr 1 + Paddock-Rockdale	3012	324	35	-1.99	0.2241
Paddock Xfmr 1 + Paddock-Rockdale	3012	355	4	-5.64	0.4701
Albers-Paris138 For Wemp-Padock 345	3522	307	52	-3.47	0.0065
Kewaunee Xfmr+Kewaunee-N Appleton	3613	306	53	4.75	0.0005
Lor5-Trk Riv5 161kv/Wempl-Paddock 345kv	3707	331	28	1.95	0.1839
Poweshiek-Reasnor 161 For Montezuma-Bondurant 345	3704	343	16	-11.11	<.0001
MHEX_N	6003	313	46	1.07	0.3831
MHEX_S	6002	341	18	-2.16	0.3769
MWSI	6004	310	49	-0.78	0.3883

The table shows the change between the spread in the downstream and upstream prices during the day of the TLR event and the spread between prices during the day following the event. The change is statistically different than zero in only three instances (i.e., p-value less than 0.05).

Taken together, the results from Table 4 and Table 5 indicate that the daily bilateral prices in the Midwest do not generally reveal the presence of transmission congestion and, therefore, fail to provide transparent and accurate price signals to market participants.

These conclusions must be tempered by the fact that prices are daily prices associated with power sold one day forward, which is the most liquid short-term trading activity in the Midwest. These prices are not as accurate as intraday hourly prices that would reflect congestion at the time it is actually occurring. However, reliable intraday prices were not available for this analysis. Transmission congestion cannot always be accurately forecasted one day ahead since it is sometimes caused by random or unexpected factors (e.g., transmission or generation outages, weather patterns, and other load determinants).

Nonetheless, we conclude that the current wholesale electricity pricing in the Midwest could be much more transparent, particularly with regard to transmission congestion. The Midwest ISO's Day-2 energy markets should substantially improve the transparency and accuracy of prices at various locations throughout the region. This transparency will lead to better signals for new investment, retirement, and forward contracting by market participants.

C. August Blackout

A blackout occurred in the Eastern Interconnect on August 14, 2003. This event was carefully studied by the U.S.-Canada Power System Outage Task Force. According to the Task Force, the blackout was caused by:

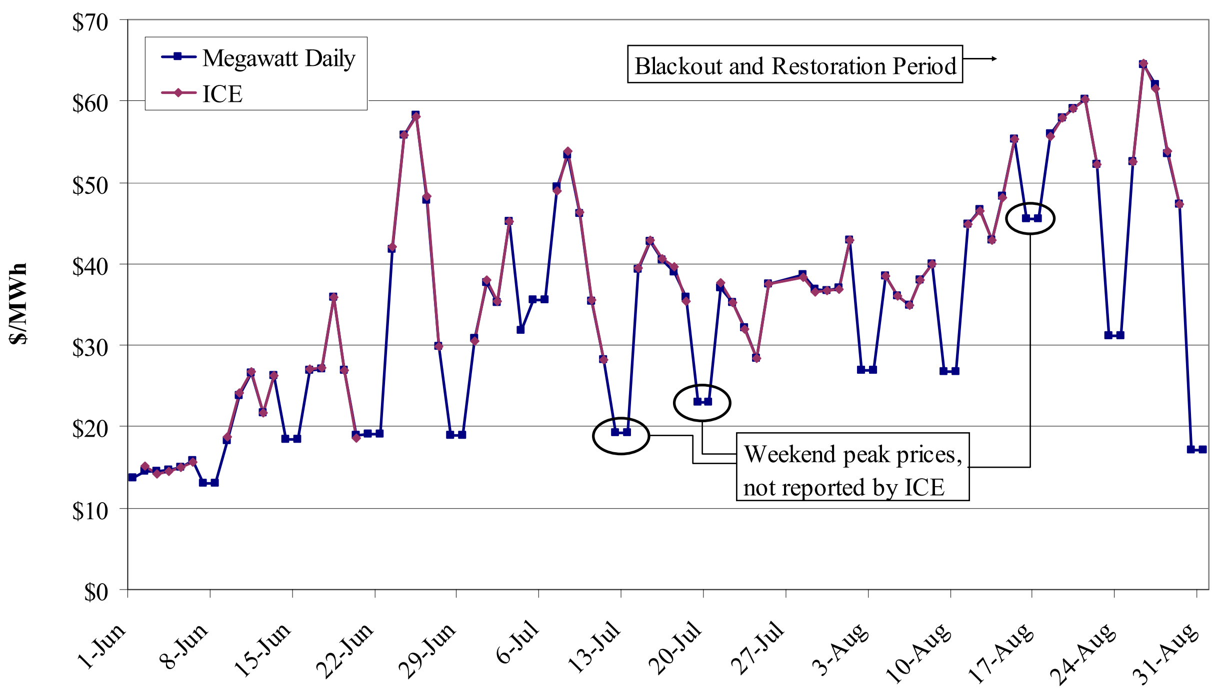
- Insufficient recognition of the voltage problems on the FirstEnergy network;
- Inadequate monitoring of the FirstEnergy Network;
- Failure to manage tree growth.

During the morning and early afternoon of August 14, low voltage conditions were experienced throughout the upper Midwest. The voltage problem was aggravated by the forced outage of FirstEnergy's East Lake 5 unit at 1:30 PM EDT, which is a major source of reactive power for voltage support in Northern Ohio. At about 2 PM, there was also a major transmission line outage on the Dayton Power and Light (DPL) system as a result of tree contact. The outage on the DPL system, while not directly affecting conditions in FirstEnergy, did degrade the ability of Midwest ISO to correctly assess subsequent events. Between 3 PM and 3:30 PM, the critical events leading to the blackout began when three high-voltage transmission lines were forced out of service on the FirstEnergy system as a result of contact with trees in the transmission right-of-ways.

While this was happening, the Midwest ISO's state estimator was unable to correctly assess the problem due to the DPL outage not being monitored by Midwest ISO (PJM is the reliability coordinator for DPL). FirstEnergy's loss of the three high-voltage lines led to emergency voltage conditions on its lower-voltage 138kV transmission system, which eventually collapsed by 4:08 PM. This over-loaded the transmission paths to the west and northwest of FirstEnergy, resulting in the loss of a substantial portion of the load in the Eastern Interconnect.

The vast majority of the load was restored over the three days following the event. We monitored the Midwest markets throughout the restoration period, including the availability of generating resources and the pattern of bilateral energy prices in the region. Figure 12 shows the prices posted by Megawatt Daily and the Intercontinental Exchange at the Cinergy Hub during the summer 2003.

Figure 12: Prices during the August 2003 Blackout



As the figure shows, prices increased by close to $7 per MWh on August 15 following the blackout. Larger increases of approximately $25 per MWh occurred during the restoration process in the weekend days of August 16 and 17 relative to the prices during prior weekends. These increases are consistent with the uncertainty that prevailed regarding unit availability and load levels during this period. Based on our monitoring of the generation outages that occurred prior to and following the blackout, we did not detect any withholding of resources or other forms of price manipulation during this period.

Finally, while some have argued that wholesale competition may have contributed to the blackout, we believe that the introduction of well-coordinated competitive electricity markets work to enhance reliability. Under LMP spot markets operated by an RTO, all generation in the region would be redispatched every 5 to 15 minutes to precisely manage the flows on the network and resolve any binding transmission constraints. The precision with which LMP markets manage the network flows is much greater than the current TLR processes used to manage congestion. These differences are discussed and evaluated below.

IV. Assessment of Transmission Service

Until the Day-2 markets are implemented, the major function of the Midwest ISO will be to provide transmission service and perform reliability coordination functions. In this section, we summarize and assess the Midwest ISO's operations relating to providing transmission service, and evaluate the behavior of market participants in reserving transmission service. We conclude that the Midwest ISO's transmission reservation and scheduling procedures have improved the coordination of transmission service in the Midwest, although further improvements are possible.

In this section, we analyze and evaluate:

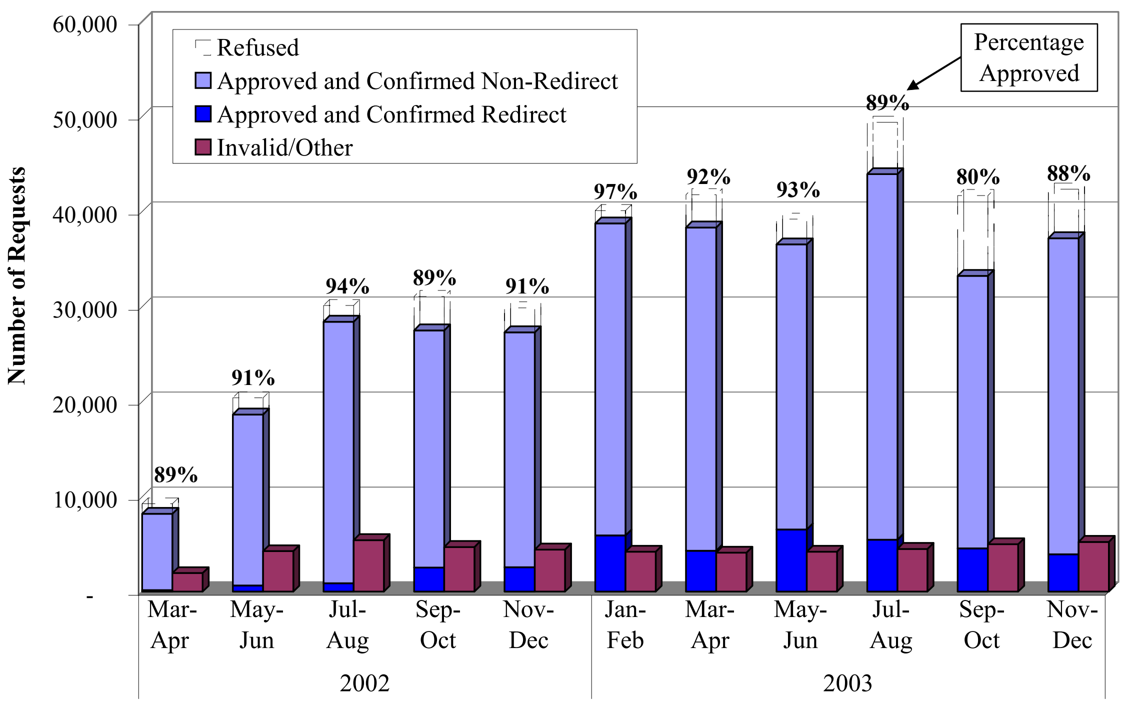
- The overall disposition of transmission service requests;
- Patterns in the long-term ATC on key interfaces;
- The practice of "redirecting" firm transmission service to an affiliate control area;
- Trends in the duration of Midwest ISO's processing of transmission requests; and
- Patterns of transmission requests that are approved by the Midwest ISO, but not ultimately confirmed by the participant to see if the failure to confirm reservations may be consistent with strategic conduct.

A. Disposition of Transmission Requests

The vast majority of transmission requests eventually fall into one of two categories: (1) approved and confirmed; or (2) refused – generally due to a lack of available transmission capability. A third category, "Invalid/Other", includes reservations that are: invalid, denied, annulled, or withdrawn. Dispositions in these categories ultimately do not result in transmission reservations due to the participant's action or the validity of the request. Some requests must be studied by the Midwest ISO before a request can be approved or refused. Because "study" is an interim designation until the study is completed and the request can be approved or refused, the figure does not include this category.

Among the requests that are Approved and Confirmed are those that are associated with "redirected" service. Redirected service occurs when a participant alters the point-of-receipt ("POR") or a point-of-delivery ("POD") for an existing firm reservation. This may be done on a firm or non-firm basis and is discussed in more detail below. Figure 13 summarizes the disposition of transmission requests in 2002 and 2003 by showing approved requests relative to refused and invalid requests.

Figure 13: Disposition of Reservation Requests in 2003

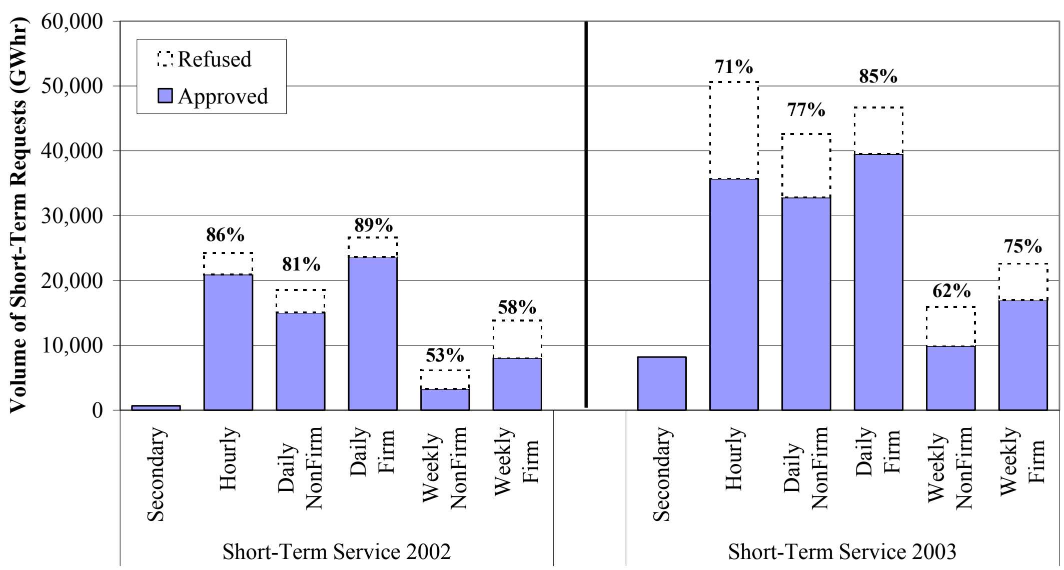


The figure reveals a number of patterns. The volume of approved requests increased from 2002 to 2003 and remained at relatively high levels throughout 2003. On an average monthly basis, the approval rates ranged from 80 percent to 97 percent in 2003, which is comparable to 2002. The "Invalid/Other" category remained at levels comparable to the levels of 2002. It is noteworthy that as long-term transmission requests are approved, the system will become more fully subscribed and approval rates will decrease.

The high approval rate and increasing numbers of approvals in 2003 indicate that transmission has generally been available for participants, which contributes to efficient wholesale trading. The figure also shows that redirected transmission service increased in 2003, but remains a relatively small share of the total reservation requests. This is examined in more detail below.

To better understand the patterns of transmission service during 2003, it is useful to show the monthly quantities approved and refused by type of service (firm vs. non-firm) and duration of service. We first show firm and non-firm requests for short-term service (hourly, daily, weekly) in Figure 14.

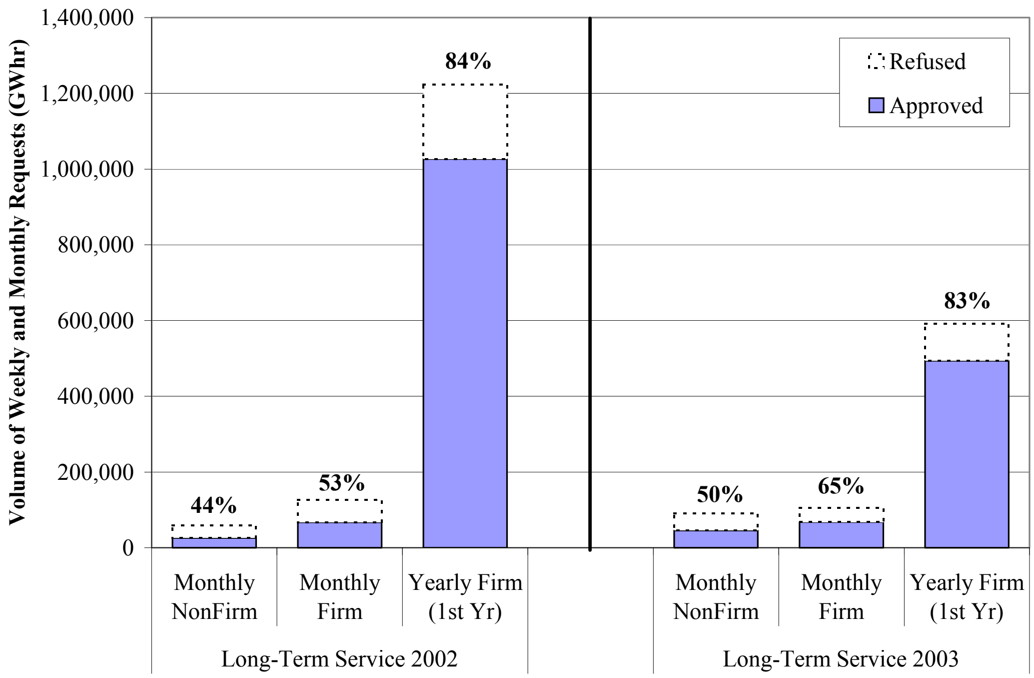
Figure 14: Disposition of Short-Term Transmission Reservation Requests



This figure shows that the volumes of approved requests for each type of transmission service increased in 2003. The approval rates in 2003 were slightly higher for weekly service and slightly lower for hourly service. Secondary service is transmission scheduling to secondary points under a firm reservation. Secondary schedules are non-firm and always approved (because they can be curtailed if necessary). Therefore, we do not report the approval rate for secondary service, which is 100 percent by design. The volume of approved requests for daily firm service in both years is higher than all other classes of short-term service.

The short-term and non-firm requests should generally exhibit a higher approval rate than long-term service because: (i) there is less uncertainty regarding available capability in the short-term, and (ii) the service imposes a lower obligation on the system. For example, the Midwest ISO must have the ability to deliver power under all conditions over a year to approve yearly firm service. But, hourly non-firm service must only be deliverable in the next hour and, if necessary, can be curtailed. Figure 15 shows the disposition of long-term transmission reservation requests for 2002 and 2003.

Figure 15: Disposition of Long-Term Transmission Reservation Requests



The figure shows that the approval rates are generally lower for long-term service than for short-term service, as expected. The volumes of service (measured in GWhs) are relatively large for long-term service because the duration of the service is much longer (e.g., one request for yearly service of a given quantity would be equivalent in GWhs to 365 daily requests). The GWhs in the figure reflect only the first year of multi-year reservations.

The figure also shows that the yearly requests account for a larger volume of requests than any other class of service. The volumes of yearly requests decreased in 2003 due to multi-year requests from 2002 that reduced available capability in 2003 and to an increasing number of yearly requests that have accumulated in the queue. The issues related to the queue are related to the current procedures to process new requests and renewals of existing long-term service. These issues are discussed below.

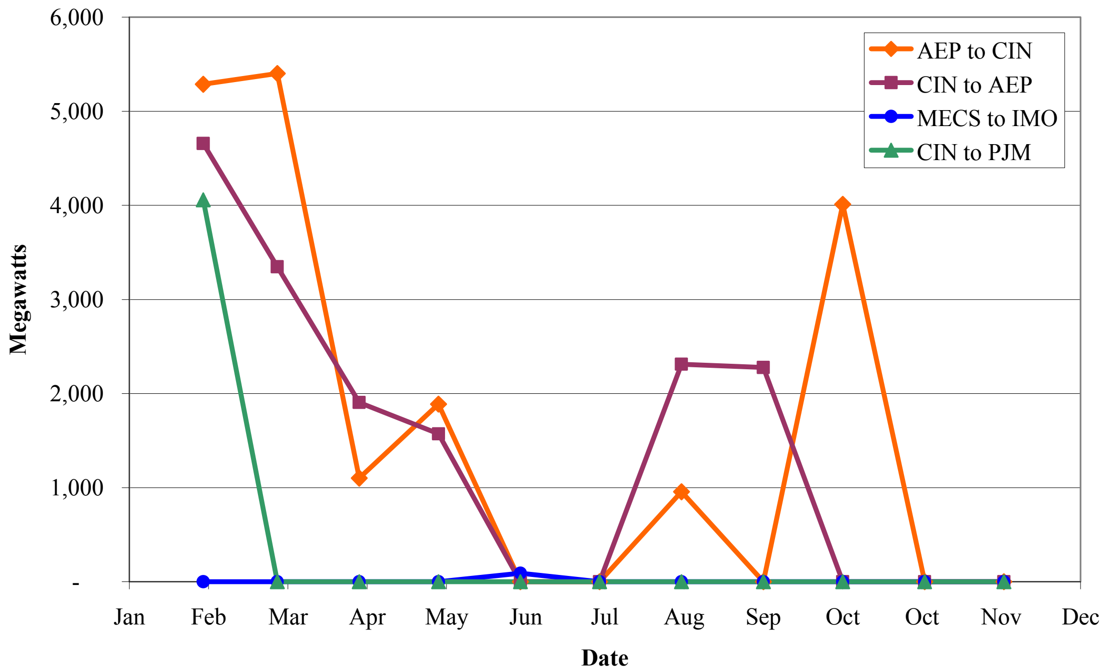
B. Long-Term ATC

In the section, we evaluate long-term ATC between the Midwest ISO and adjacent areas. Long-term ATC is used to support firm sales and purchases for periods of one year or longer. Firm purchases and sales are used by market participants to meet capacity and reserve margin requirements and for long-term energy commitments. When ATC is available between adjacent areas, trading of long-term energy and capacity can occur that improves the efficiency of regional markets.

Given the importance of inter-regional trading, we evaluated ATC between the Midwest ISO and adjacent areas. For two reasons, our primary focus in this analysis is on the interfaces between the Midwest ISO and PJM. First, liquid trading over these interfaces is important in promoting efficient market outcomes in the Midwest. Second, the elimination of the through-and-out rates between the Midwest ISO and PJM in December 2004 will likely reduce the availability of transmission service over the PJM interfaces and raise potential transmission hoarding concerns. Because Cinergy is the most liquid trading location in the Midwest ISO, we evaluated three paths between Cinergy and current or future PJM locations: the AEP to Cinergy path; the Cinergy to AEP path; and the Cinergy to PJM path. We also evaluated the Michigan (MECS) to Ontario (IMO) path.

The ATC estimates are derived from the posted AFC values based on how much of the transaction on a given path would actually flow over each flowgate comprising an interface. The ATC between two points is equal to the quantity of transfers between the points that could occur until a flowgate constraint would bind. Figure 16 shows the trends in estimated long-term ATC values for each path during 2003.

Figure 16: Long-Term ATC between Selected External Areas February to December 2003



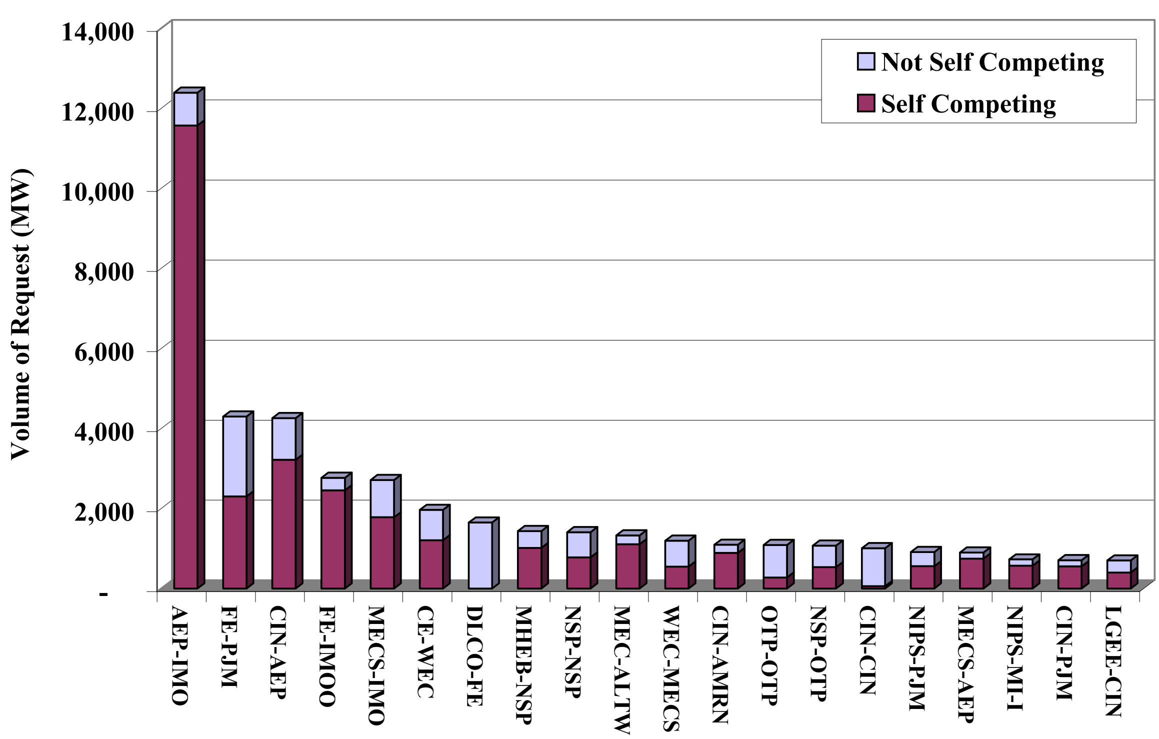
The figure indicates that long-term ATC values have decreased over the year and are generally very low. The estimated ATC values for the Cinergy to PJM path and for the MECS to IMO path are close to zero throughout 2003. Declining ATC values may be explained by four factors. First, the underlying AFC values are reduced while a transmission request is pending. The time it takes for a pending request to be resolved can be substantial under some circumstances. One reason for this is that the ISO requires time to study the feasibility of longer-term requests. There is also a period of time required for the requesting participant to determine whether it will pay for a study and to confirm the reservation if it is approved. When AFC capability is "under study", the capability is unavailable for all paths that would affect the same flowgates.

Second, ATC values may be low due to large numbers of requests that may, in part, be caused by the elimination of through and out charges for reservations between the Midwest ISO and PJM in December 2004. Hence, participants face no cost in making a reservation to the PJM border and are likely to do so to have the option to trade when profitable opportunities arise. Third, requests are high because long-term transmission rights, even those acquired recently, provide the holder an entitlement to an allocation of the FTRs. This provides an incentive to reserve the capability on congested paths.

Finally, the rules and procedures governing the queuing process provide incentives for participants wanting to acquire or retain long-term capacity on congested interfaces to submit numerous requests. These rules may allow a participant to benefit by having numerous requests in the queue, even if the participant intends to confirm only one of the requests. We refer to these types of requests as "self-competing" requests.

In the following analysis of self-competing long-term requests, we consider self-competing requests to be those requested by the same participant over the same path, and which straddle a fixed point in time (June 1, 2004 in our analysis). Additionally we define self-competing requests to not include the first request made by the participant or any requests that are ultimately confirmed by the participant. To evaluate whether the current rules may be causing participants to submit self-competing requests, Figure 17 shows the volumes of requests on the twenty most heavily requested paths.

Figure 17: Self-Competing Long-Term Transmission Requests



The figure shows that a high percentage of the requests on these paths are self-competing. Self-competing transmission requests have little value from the perspective of efficient competition for the transmission capability. At little or no cost, participants can occupy a substantial portion of the queue to give themselves an option to buy the transmission service and restrict its available to other participants. The result of this activity is that the transmission capability is made unavailable and may not be allocated to the participants that value it the most highly.

The Midwest ISO is examining measures to improve the long-term request and queuing process. Among the options that we believe would be beneficial is charging a processing fee for requests that would increase with the duration of service.

C. Redirected Transmission Requests

The next reservation and scheduling practice that we evaluate is the "redirecting" of firm service to an affiliated control area. Market participants with firm transmission reservations are able to redirect a firm reservation to alternative receipt or delivery points. Firm service that is redirected to secondary points on an hourly basis becomes non-firm. Firm service can also be redirected on a firm basis for a term that is less than or equal to the original reservation term (e.g., a firm monthly reservation could be redirected firm on a monthly or daily basis). The vast majority of the revenue associated with the redirected service is allocated to the control area associated with the redirected delivery point.[8] Hence, these rules provide an incentive for participants to redirect service back to their affiliated control areas in order to retain the transmission revenues. The analysis in this section evaluates the extent of this activity during 2003.

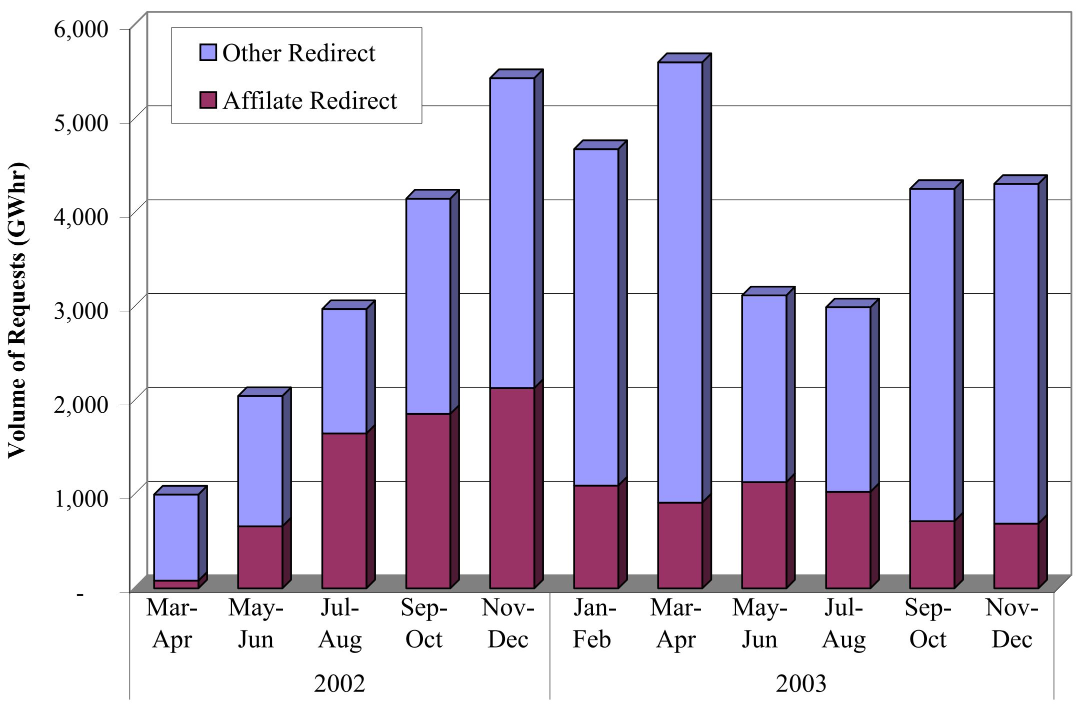
The ability to redirect firm service is a beneficial aspect of the Midwest ISO tariff. It increases the value of the transmission service to participants by allowing them to engage in transactions on those paths that are most valuable to them without having to purchase additional transmission service. This will be efficiency-enhancing when it leads to a

8 See §6.9 of the Business Practices Manual. When the redirected receipt point and delivery point are the same (i.e., within a control area) then approximately 94% of the revenue is allocated to that control area.

higher utilization of the transmission system. Even redirected reservations to an affiliate may not raise significant issues to the extent that they support actual transactions made to lower the costs or increase the profit of the participant (excluding the re-allocation of the transmission revenue).

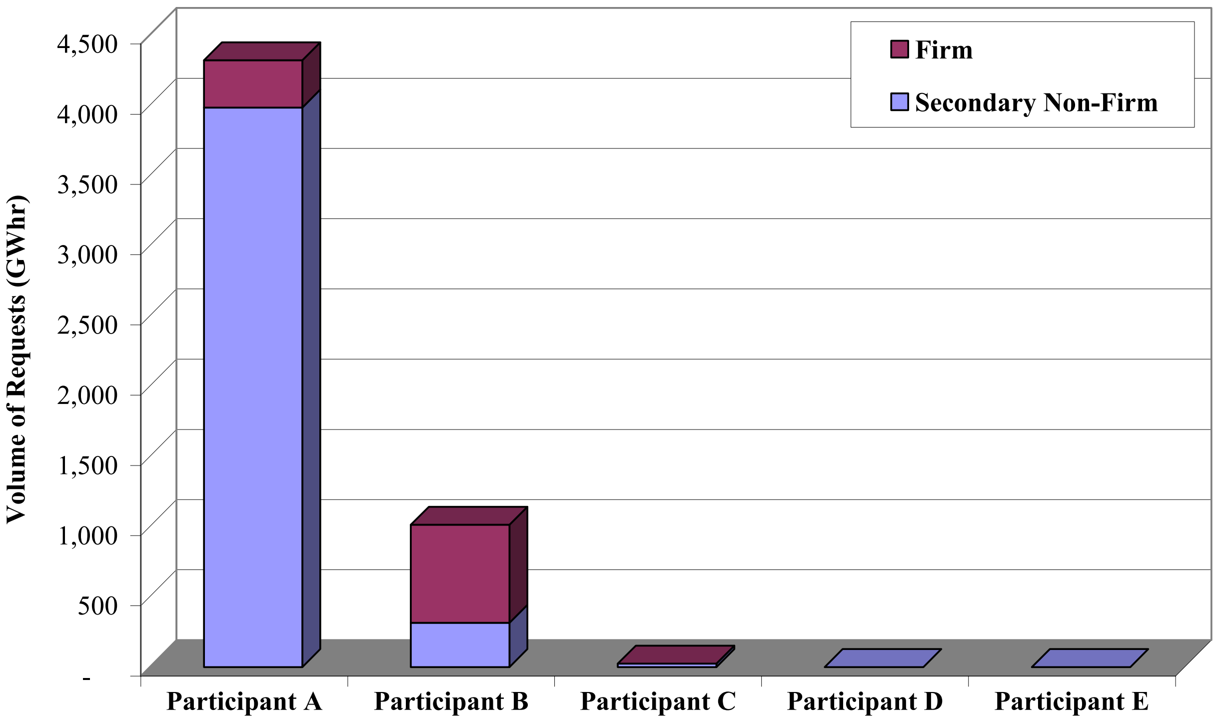
However, redirected service that is done solely to shift revenue has no competitive value. If the original point of receipt is the affiliate's control area and the point of delivery is another control area, and this is subsequently redirected so the point of delivery is the affiliate's control area (such that the receipt and delivery points are both the same), this schedule will not result in power flows and serves only to re-allocate revenue to the affiliate. Figure 18 shows the total monthly volume of transmission service redirected to an affiliate's control area and to other locations.

Figure 18: Redirected Transmission Requests in 2003



This analysis shows that the total volume of redirected service increased in 2002 before decreasing in 2003 and remaining relatively level throughout the year. Overall, the portion of redirected reservations to an affiliate compared to the total redirected volume is slightly less than 30 percent. To further evaluate this conduct, we have quantified this activity by market participants. The results of this analysis are shown in Figure 19.

Figure 19: Redirected Transmission Service to an Affiliate's Control Area 2003



This figure shows that most of the redirected reservations to an affiliated system were initiated by a single participant. It also shows that most of the redirected service was redirected on a secondary non-firm basis, which requires no advance approval by the Midwest ISO. Based on our review of the Midwest ISO's formula rates (see Attachment O of the Midwest ISO OATT), it does not appear that the revenue reallocated by redirecting the firm reservation would reduce a transmission owners zonal rate in the following year. Hence, the current rules provide an incentive to engage in this conduct.

The ability to redirect firm transmission service to an affiliate's control area provides a competitive advantage to power marketers and other participants that are affiliated with a Midwest ISO transmission owner. It also effectively allows them to hold an option on firm transmission at little or no cost. In other words, a participant is able to reserve firm transmission over a path in the Midwest ISO region, redirecting it to its affiliate's control area when it does not intend to use it. This gives the participant the option to use the transmission service without incurring the full costs of the service since the affiliate will receive the transmission revenue when it is redirected.

We will continue to monitor this conduct. Although it has not been widespread to date, we recommend the Midwest ISO consider modifications to Business Practices that would eliminate this incentive. One such modification that should be considered is for the revenue to remain allocated to the original firm path when service is redirected on a secondary non-firm basis such that the POR and POD are the same control area.

D. Unconfirmed Transmission Requests

In this section, we evaluate the practice of participants not confirming transmission requests that have been approved by the Midwest ISO. Available transmission capability is reduced from the time a transmission request is made until it is refused or withdrawn. Hence, the capability will remain unavailable while the Midwest ISO awaits confirmation from the participant. If the approved request is not confirmed by the market participant within the time allotted for confirmation, the request is withdrawn and the capability is made available to the market.

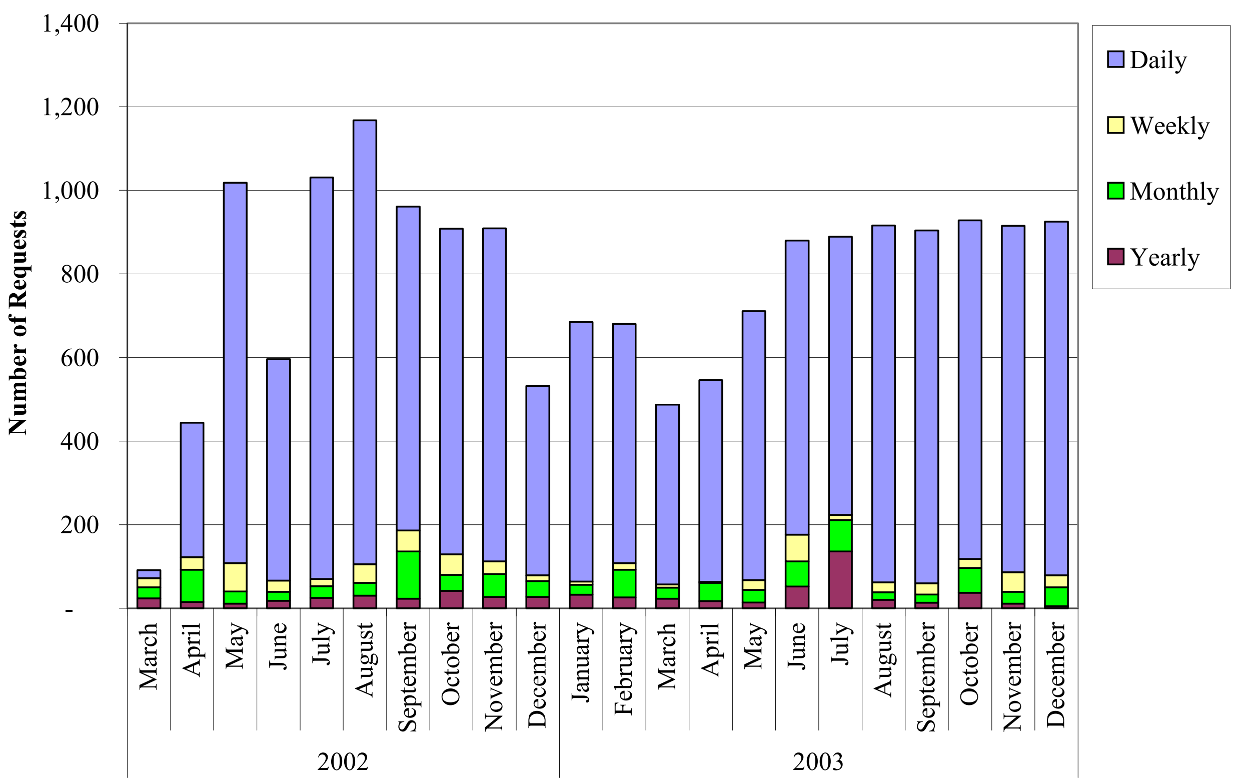
For daily firm service, requests can be made up to 14 days in advance. If the Midwest ISO approves the request, the participant has 24 hours to confirm the request, provided it is submitted more than 24 hours in advance, otherwise the service must be confirmed within two hours. Participants have a longer time to confirm longer-term service (e.g., 15 days for yearly firm service) as specified in Attachment J of the Midwest ISO's OATT.

Allowing time for participants to confirm an approved request is valuable for market participants, particularly if they must arrange service from other transmission providers to support a transaction. Perhaps the largest benefit of this process is that it provides participants with a free call on the transmission service. By holding an approved firm reservation, the participant receives an option at no cost to confirm and use the service or not to confirm the service and let it be withdrawn. Presumably, the participant would exercise the option to confirm the service on those days when a profitable opportunity emerges to transfer power across the given interface.

Additionally, we note that capability can be secured well in advance by submitting a series of short-term firm requests. For example, daily firm requests can be submitted 14 days ahead to fully hold a given interface. Other requests will then be refused. The participant can then synchronize new requests for the same day for the time when its prior unconfirmed request is withdrawn and capability is momentarily available. When the day arrives, the participant will then have the option to use the service.

This conduct can adversely affect the market because the capability remains unavailable to other participants during the timeframe allotted for participants to confirm the request. Hence, large quantities of accepted requests that are ultimately unconfirmed and withdrawn can cause transmission to be under-utilized. It can also signal that participants are using the confirmation process to strategically hoard transmission capability, which we evaluate in this section. Figure 20 shows the number of unconfirmed requests in each month for various types of service.

Figure 20: Trend in Unconfirmed Transmission Requests in 2003

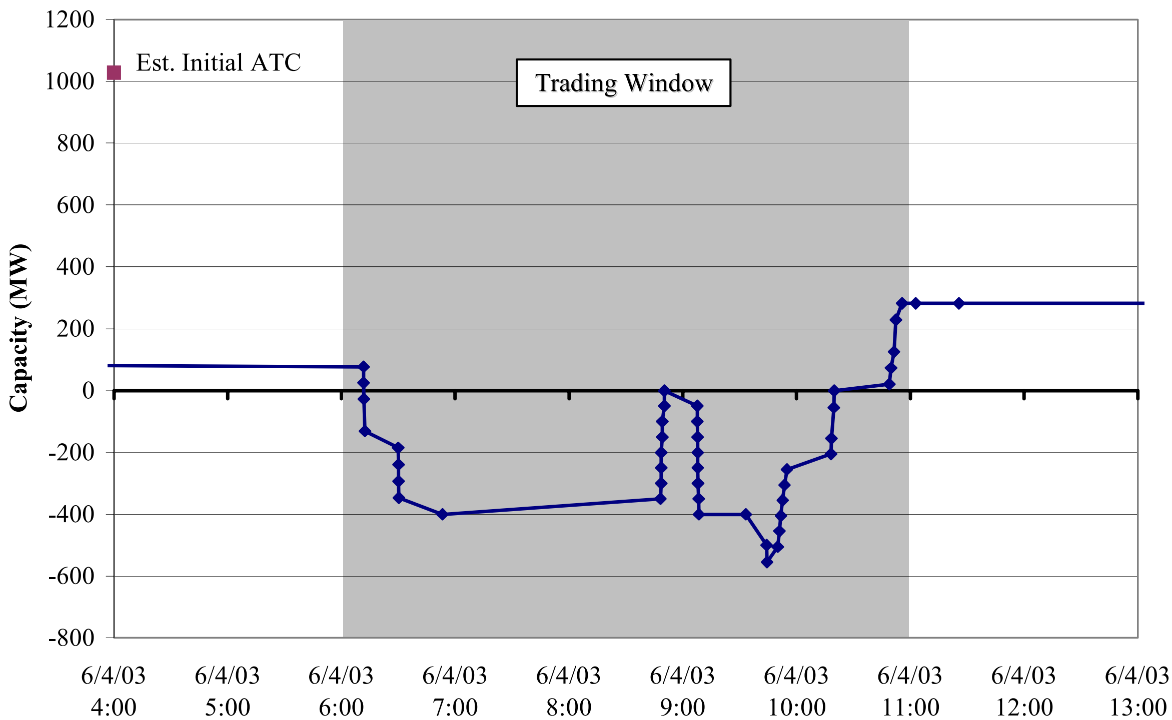


The figure indicates that the number of unconfirmed requests has not increased substantially from 2002 to 2003. The analysis also shows that the largest quantity of unconfirmed requests is for daily firm service. Hence, we evaluated the patterns of unconfirmed requests for daily firm service to determine whether they indicate potential hoarding of transmission. We considered an unconfirmed request to be potential hoarding if three conditions were met:

- The daily firm ATC was zero during the trading window in which marketers and other participants make trades for the next day (6 AM to 11 AM central time);
- Midwest ISO refused requests for daily firm service on the path; and
- The ATC was greater than zero at the end of the reservation period for the service (i.e., daily firm capability went unsold).

Figure 21 shows an example of a day when these three conditions were met on the Cinergy to TVA path.

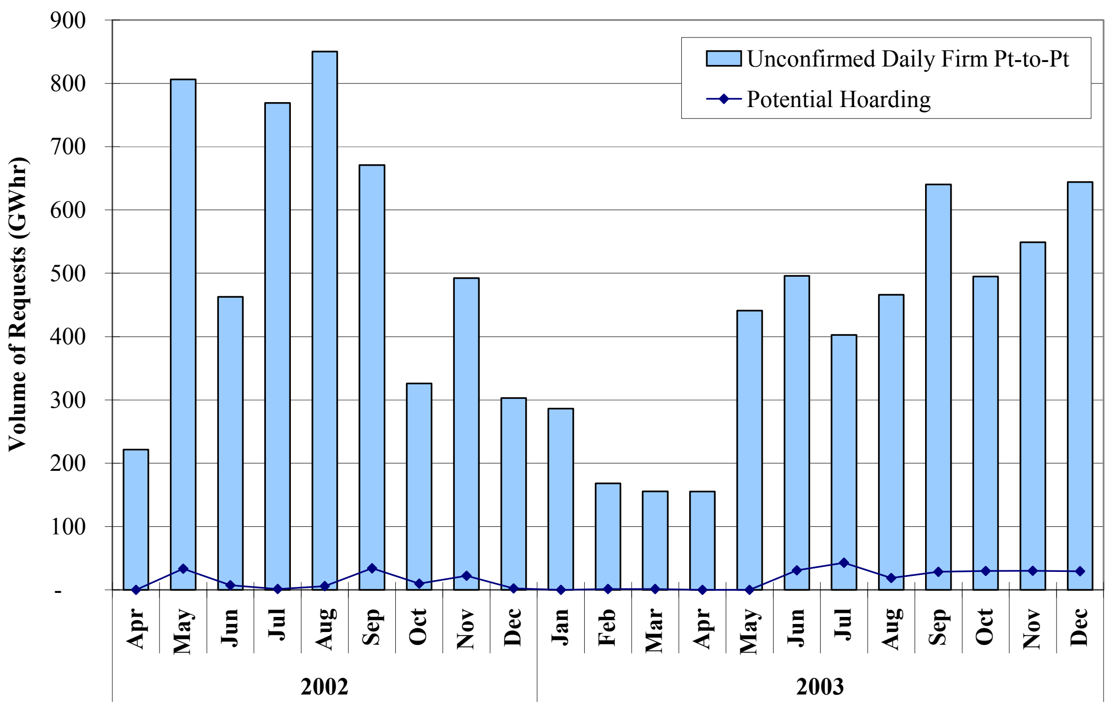
Figure 21: Estimated Firm Daily ATC – Cinergy to TVA



Although the initial ATC on the path was close to 1000 MW, the figure shows that there was no ATC during the most of the intervals in the trading window (6 AM to 11 AM). Due to the lack of ATC, a number of requests were refused during the trading window. One can see in the figure when new requests were made during the trading window (the ATC declines sharply) and when the requests are refused (the capability rises sharply, but remains less than zero). However, 300 MW of ATC became available after the trading window because the approved requests were not confirmed by the participants.

Figure 22 shows the total volume of unconfirmed daily firm requests by month. To evaluate whether these unconfirmed requests may indicate transmission hoarding, we applied the three criteria described above. The requests that satisfy these three criteria are shown in the figure as "potential hoarding".

Figure 22: Approved and Unapproved Requests and Potential Hoarding



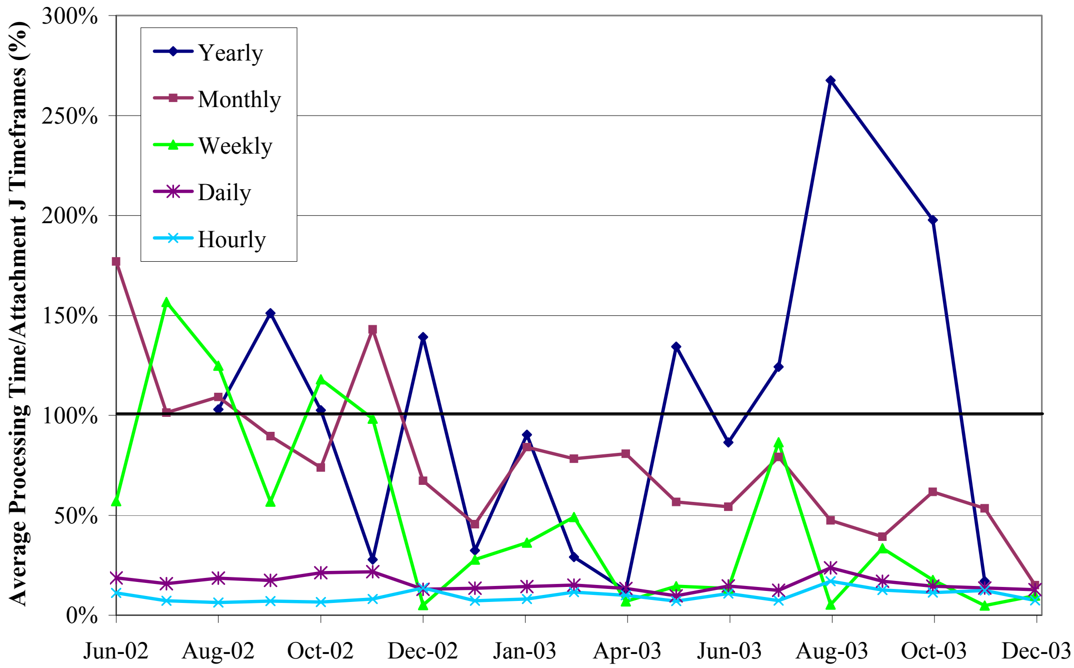
These results show that there has not been a substantial quantity of unconfirmed requests that meet these criteria. Hence, we do not find that market participants have used the daily firm point-to-point transmission reservation process to hoard transmission. Although we do not find evidence of hoarding, the quantities of unconfirmed reservation requests are relatively large. We find the cause of these patterns is most likely related to the incentives provided by the current tariff. As discussed above, the tariff provides participants a free call option on firm transmission service during the time allotted for them to confirm an approved request. This call option can be valuable on days when a significant basis differential emerges in the bilateral market. Because this conduct can block participants' access to firm service at times and lead to under-utilization of the transmission system, we recommend the Midwest ISO consider tariff revisions to eliminate this "free call" aspect of the tariff.

E. Duration of Transmission Reservation Process

Our final analysis of Midwest ISO transmission service evaluates the duration of the reservation process for various types of transmission service. We calculate the average time to achieve a final disposition of a transmission request and compare this value to the maximum timeframe specified in Attachment J to the Midwest ISO OATT for each type of service. These values are evaluated by calculating a ratio of the processing time to the Attachment J timeframe. A ratio greater than 100 percent indicates that Midwest ISO exceeded the maximum time frame specified the Attachment J.

For reservations for service increments of a month or longer, the time used to achieve a final disposition could include actions by both the Midwest ISO and the participant. In particular, if a study is required to determine ATC sufficiency, the Midwest ISO has a longer response time than when a study is not needed. Additionally, the participant will take time to decide whether or not to have the study conducted. Our data was not sufficient to determine whether a study was required. We assume no study is needed for these requests, which shortens the assumed time the Midwest ISO is required to process the request from 60 days to 30 days for reservations of one month or longer. This will tend to make the values appearing in the following figure slightly higher. Figure 23 shows the full results of our analysis.

Figure 23: Processing Time for Transmission Requests
June 2002 – December 2003



The figure shows that the processing of daily and hourly service has remained relatively fast. Much of the process is automated for these classes of service. The figure also indicates that the time to achieve final disposition of longer-term weekly and monthly service has decreased from 2002 to 2003, suggesting improvements in the Midwest ISO's analysis and processing. The time to achieve final disposition of yearly service has been highly variable. The processing of this service has become increasingly difficult due to excessive volumes of yearly requests.

Based on our review of these requests (along with the analysis in the preceding section), we believe that many of these requests are being made to compete with other participants through the queuing process to acquire or retain transmission capability. This form of queue-based competition is not efficient and does not ensure the participants that value the transmission capability most highly will be able to acquire it.

The Midwest ISO is currently examining options for improving the long-term request and queuing process, including charging a processing fee for requests. Based on the ATC results in this subsection, as well as our analysis of self-competing requests, unconfirmed requests, and long-term ATC on key interfaces, we support these efforts. Changes to the current tariff, while constrained substantially by prior FERC orders[9], can improve the incentives of participants in the reservation process. Such improvements would increase availability of transmission service and ensure it is allocated to those participants that value it most highly.

9 For example, see Order 888-A, FERC Stats. & Regs. ¶ 31,048 (1997) and Order 638, FERC Stats. & Regs. ¶ 31,093 (2000).

V. Midwest ISO Operations

While the prior section reviews the transmission service sold prior to the operating timeframe, this section examines the Midwest ISO's operations related to its management of congestion and hourly AFC calculations. We examine three primary areas in this section. We first examine the pattern and frequency of TLR events and curtailments associated with these events. This includes examining TLR events by region and evaluating whether TLR procedures have been implemented consistently. A second area of analysis is the efficiency of the TLR process as a method of managing congestion relative to operating RTO markets that employ market-based redispatch of generation to manage congestion. The third analysis addresses the hourly AFC values. In this area, we review the amount of physical capability available in real time on flowgates when the posted non-firm AFC is zero.

A. TLR Events: Patterns and Frequency

The Midwest ISO manages transmission congestion through the NERC TLR Procedures.[10] Under these procedures, the Midwest ISO monitors real-time flows on flowgates relative to their operating limits. When a flowgate exceeds its limit or is expected to exceed its limit (e.g. based on next hour scheduled transmission service, current hour ramping schedules, or other factors), security coordinators will take actions under these procedures to relieve line loadings.

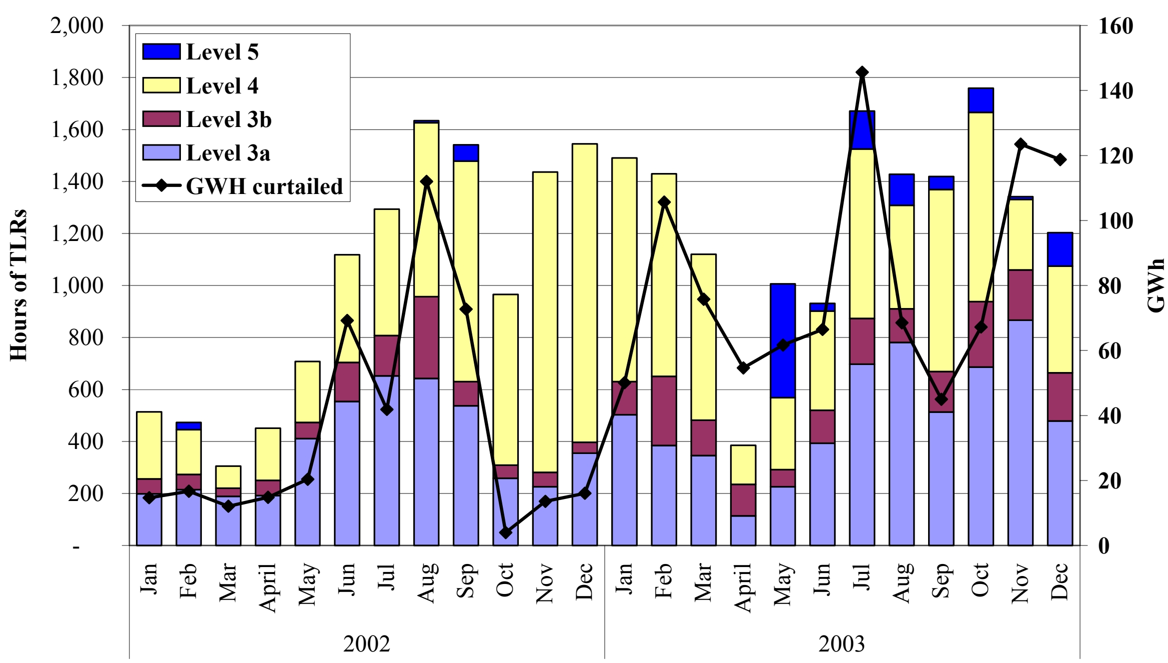
One of the primary actions reliability coordinators may take to manage congestion is to invoke a TLR procedure. TLR events have a number of levels. A Level 3a TLR event affects transactions in the next hour by holding or curtailing the lowest-priority non-firm schedules to allow higher-priority service to be scheduled or to decrease the flow on the relevant flowgate. A Level 3b TLR event affects transactions in the current hour, resulting in curtailments of non-firm transmission service (lowest priority first) as needed

10 See NERC Policy 9 and Appendices 9C1, "Transmission Loading Relief Procedure – Eastern Interconnection"; 9C1B, "Interchange Transaction Reallocation During TLR Levels 3a and 5a"; 9C1C, "Interchange Transaction Curtailments During TLR 3b"; and the "Parallel Flow Calculation Procedure Reference Document".

to maintain reliability. Under a Level 4 TLR event, generation will be redispatched or the transmission system will be reconfigured to provide relief for the flowgate. For example, American Transmission Company coordinates a redispatch process that is used to resolve congestion within Wisconsin and Upper Michigan when a Level 4 TLR event is invoked. Under Level 5a and 5b TLR events, firm transmission schedules are put on hold or curtailed. Under a Level 6 TLR event, emergency actions are invoked.

The real-time flows over each of the Midwest ISO flowgates, based on information from meter readings and its state estimator, are captured in the Midwest ISO's real-time flowgate monitoring tool ("FGMT"). The FGMT alerts reliability coordinators when flows are approaching the operating security limit ("OSL") of a flowgate. When this occurs, the Midwest ISO operators use the Interchange Distribution Calculator ("IDC") to identify current and future transmission schedules for which 5 percent or more of the associated power flows occur on the given flowgate. These are the transactions that would be subject to curtailment if the Midwest ISO must invoke a TLR to relieve the flow on a flowgate. Figure 24 provides a summary of the Midwest ISO's TLR activity in 2002 and 2003, including the quantity of transactions curtailed.

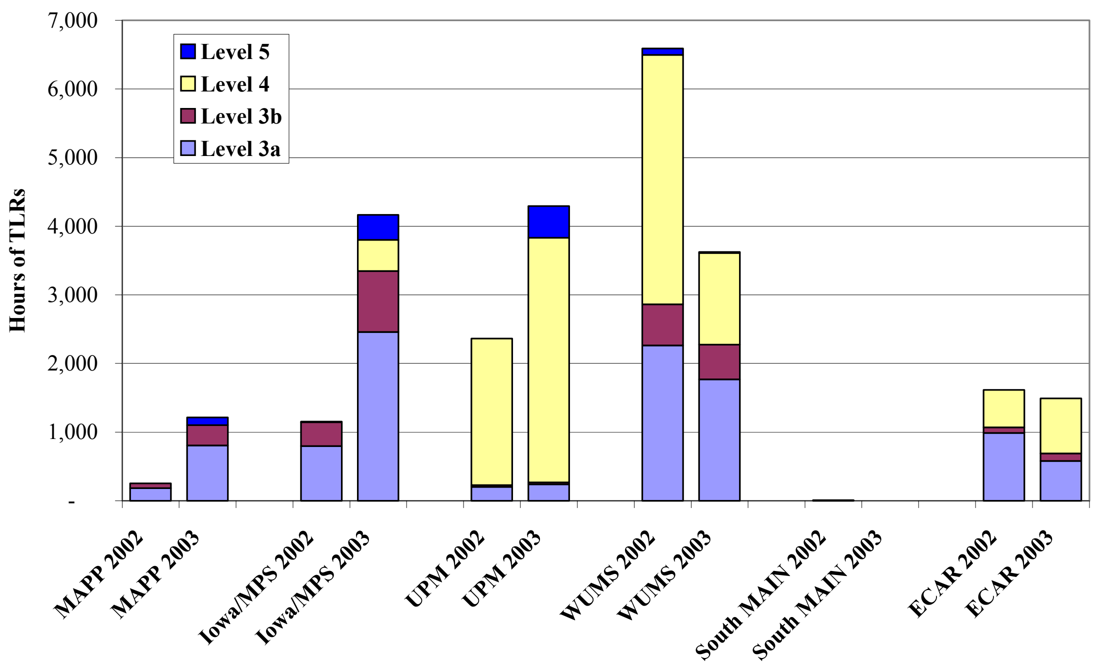
Figure 24: TLR Events and Transactions Curtailed 2002 - 2003



The TLRs called on Midwest ISO flowgates (level 3 and above) accounted for 62 percent of all TLRs called in the Eastern Interconnect in 2003. The Midwest ISO's considerable share of total TLR events can be explained by the fact that much of the Eastern Interconnect is operated under LMP or other central markets that redispatch generation rather than utilizing TLR procedures to manage congestion.

Figure 24 shows that the curtailment quantities have increased significantly from 2002 as has the number of TLR events. The figure shows that in some months, curtailments rise as TLR events increase. In some months, however, curtailments decline even as TLRs increase. Part of this is explained by the re-dispatch process used by American Transmission Company to manage congestion in WUMS. To better understand the patterns of TLRs occurring within the Midwest ISO region, Figure 25 shows the TLR events and transactions curtailed by sub-region in 2003 and 2002.

Figure 25: TLR Events by Sub-Region in 2003



The figure indicates that the three areas with the most TLR events are WUMS, the Upper Peninsula of Michigan ("UPM"), and Iowa/MPS. A large share of the TLR events in WUMS and UPM are Level 4 TLR events, which result in redispatch of generation by

American Transmission Company, as described above. The primary cause of the increase in TLR events in the UPM, particularly the Level 5 TLRs, was an extended outage at the Presque Isle plant in the UPM that required many hours of redispatch and firm curtailments (including interruption of load) to manage the flows into that area.

The TLR activity into the broader WUMS region was significantly higher in 2002 than 2003 due to transmission outages on the western interface into WUMS in 2002. Finally, one of the primary causes of the increased TLR activity in Iowa was the relatively light hydro conditions for Manitoba Hydro, which significantly affected the schedules and flows through the MAPP region.

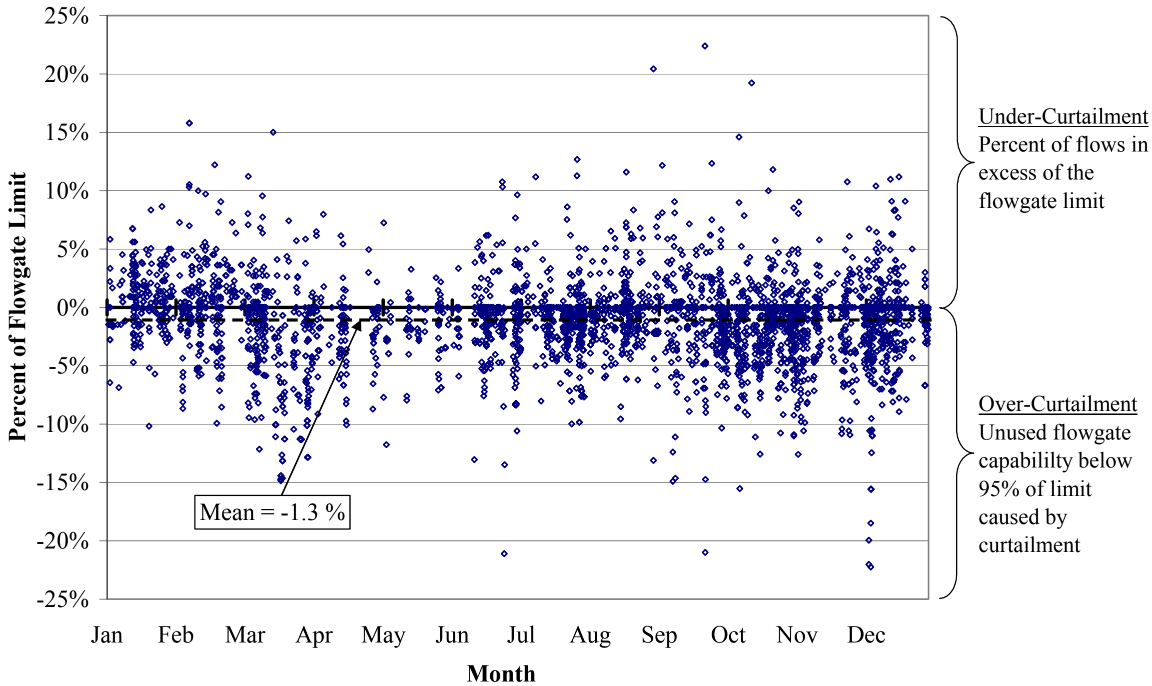
B. Evaluation of TLR Calls and Curtailments by the Midwest ISO

In our next analysis, we evaluate more closely the Midwest ISO's TLR events in 2003. To do this, we examine the flows on each of the flowgates in hours when TLR events occurred. A TLR should be called when the flow on a flowgate is approaching its limit. When a TLR is called, curtailments are requested to reduce the flow to 95 percent of the flowgate limit. This target range exists in part because there are significant uncertainties in the TLR process.

The uncertainties in the TLR process include the amount of relief that will be needed. Operators are forecasting the operating conditions for next hour more than 20 minutes before the hour, which can be more than an hour before the relief is forecasted to be needed. There is also uncertainty as to the level of the relief that any particular curtailment will provide because transactions are modeled from control area to control area. Because the actual redispatch of generation is not known, the resulting relief on the flowgate is uncertain.

To evaluate the Midwest ISO TLR events in 2003, we analyze the system conditions and results of each TLR event of level 3 or higher to determine whether the Midwest ISO's actions resulted in an over-curtailment or under-curtailment. An over-curtailment is a curtailment that causes the flow to be less than 95 percent of the flowgate OSL. An under-curtailment is one in which additional relief is necessary to reduce the flow to the flowgate OSL. We measure the flow at the middle of the TLR hour to control for the effects of ramping, which can be higher or lower than the actual flow at the beginning or end of the hour. Level 4 TLR events are not included because they result in redispatch rather than curtailments. Figure 26 shows the over-curtailment or under-curtailment for each TLR event in 2003.

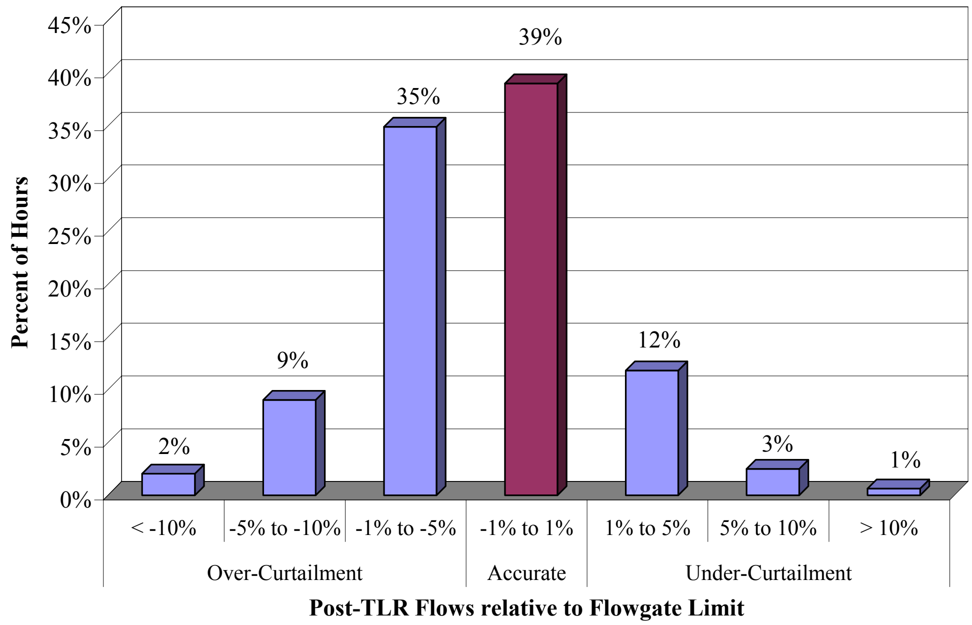
Figure 26: Over-Curtailments and Under-Curtailments during TLR Events 2003



The analysis indicates the bulk of the curtailments are in the range of 5 percent over-curtailment to 5 percent under-curtailment, with some outliers. On average, TLR events resulted in an over-curtailment of 1.3 percent.

To better show the relative quantities of over-curtailments and under-curtailments, we show how these curtailments were distributed during 2003. Figure 27 shows the distribution of over-curtailments and under-curtailments over the year, indicating the percentage of TLR hours in which the over-curtailment or under-curtailment fell in specific ranges.

Figure 27: Distribution of Over-Curtailments and Under-Curtailments 2003



The figure shows that 39 percent of the curtailments are accurate, with over-curtailments or under-curtailments of less than 1 percent of the flowgate limit. More than 86 percent of the curtailments exhibit over-curtailments or under-curtailment amounts of less than 5 percent of the flowgate limit. These results are encouraging considering the uncertainties inherent in the TLR process.

As a final analysis of over-curtailments and under-curtailments, we sought to identify any cases where the Midwest ISO was slow in invoking a TLR, allowing the flow to rise above the flowgate limit. To do this we identified every interval on every flowgate where the flow was greater than 100 percent of the limit and no TLR was invoked. Our analysis showed that these cases were extremely rare. The average frequency of such conditions over all the flowgates was less than 0.02 percent of the intervals (i.e., close to 2 hours) from January to December 2003. The highest frequency on any flowgate was 0.9 percent.

Based on the results of these analyses, we conclude the Midwest ISO's operators invoked TLR procedures in a consistent and justified manner.

C. Analysis of TLR Efficiency

Although the Midwest ISO has implemented TLR procedures justifiably, the procedures are not an efficient means to manage congestion. TLR procedures are inefficient because they make no attempt to optimize the curtailments (i.e., to redispatch the generation with the largest effect on the flowgate). In addition, the TLR curtailments themselves are subject to limited resolution in both time (they are essentially hourly) and space (control area versus node or bus).

With regard to the timing of the TLR calls, reliability coordinators are required to make decisions on TLR curtailments based on a combination of real-time information, forecasts of future flows, and the inherent lags in the participant's actions (including the permitted lag on the ramping of curtailed transactions). With regard to spatial resolution, the Midwest ISO relies primarily on the IDC to select transactions eligible for pro-rata curtailment. Transactions selected for curtailment using the IDC are selected based on Transmission Distribution Factors ("TDFs") -- including only transactions exhibiting a TDF greater than 5 percent are eligible for curtailment. The actual impact on the flowgate of a curtailment (based on the generators that will be redispatched as a result of the curtailment) can be very different than the TDFs would imply since the TDFs are estimated at the control area level.

Efficient congestion management is one of the significant expected to be achieved when the Midwest ISO introduces Day-2 LMP energy markets. The analysis in this section evaluates the likely differences in the outcomes of the TLR procedures versus the economic dispatch process resulting from an LMP market. Our analysis in this sub-section compares the results of the TLR process to a simulated redispatch of generation to manage the same congestion.

Our analysis examines TLR events by flowgate to determine the quantity of redispatch that would have been necessary to achieve the same relief that the TLRs provided, including only flowgates with at least 5 TLR events in 2003. The redispatch quantity is determined by using the most effective generating units (based on their generation shift factors) to relieve the flow on the flowgate. Hence, the results of this analysis shown in

Table 6 include the average amount of flowgate relief required per event, the average amount curtailed to achieve the relief, and the redispatch amount that would have been necessary to achieve the same relief.

Table 6: Redispatch Ratio by Flowgate for TLR Events

					Comparison Statistics	
Flow Gate	TLR Events	Relief Provided (MW)	Curtailed Amount (MW)	Redispatch Amount (MW)	Redispatch Ratio	Excess TLR Curtailments
11Blue L 161 20Blit C 161 flo 06Clifty	6	15	261	115	44%	128%
12w Lexi 345 12Brwn N 345	8	13	172	45	25%	306%
Paddock Xfmr 1 + Paddock-Rockdale	32	24	156	53	32%	214%
Rockdale 345-138 T2 Flo Rockdale 345-138	14	26	182	101	47%	114%
Albers-Paris138 For Wemp-Paddock 345	48	16	185	93	46%	118%
Poweshiek-Reasnor 161 For Montezuma-Bond	29	9	154	43	28%	254%
Arnold-Hazelton 345 For Wemp-Paddock 345	17	33	267	78	30%	234%
Arnold – Hazleton	5	52	395	135	33%	201%
Lore-Turkey River 161 (Flo) Wemp-Paddock	24	17	175	115	58%	73%
Arnold-Vinton 161 For D.Arnold-Hazleton	40	13	221	45	19%	422%
Lakefield-Fox Lk 161 For Lakefield-Lgs 3	18	18	224	58	19%	436%
Wisdom-Triboji 161 Flo Raun-Lakefield 34	5	25	230	104	39%	157%
Lakefield-Fox Lake 161 (Flo) Lakefield-W	11	18	259	52	16%	522%
Genoa-Coulee Flo Genoa-Lacrosse-Marshland	15	10	153	49	32%	216%
Montezuma-Bondurant 345kv	42	26	329	63	17%	482%
Sub K/Tiffin-Arnold 345kv	13	32	304	72	22%	347%
S1226-Tekamah 161kv Flo S3451-Raun 345kv	13	22	234	105	44%	126%
Weighted Average Redispatch Ratio					**31%**	**218%**

The table reports two comparison statistics for each flowgate to compare the amount of generation that must be redispatched to achieve the same relief as the TLR curtailment. The first is the *Redispatch Ratio*. The Redispatch Ratio is the redispatch amount divided by the curtailment amount. A ratio of 50 percent would indicate that the redispatch amount was one-half of the curtailment amounts. The second is *Excess TLR Curtailments*. This statistic indicates the additional quantity of TLR curtailments beyond the redispatch amount as a percent of the redispatch amount. Hence, 100 percent means the curtailment amount was double the redispatch amount.

This analysis shows that the TLR process, on average, curtails more than three times the quantity of transactions as could be redispatched to achieve the same result. It also shows that for the individual flowgates, the TLR curtailments ranged from 73 percent more than the redispatch amount to 472 percent more (almost six times the redispatch amount). These results indicate that the TLR process is substantially inferior to a more discriminating approach to managing congestion, such as the Day 2 LMP markets. The Day 2 LMP markets will result in substantial efficiency benefits by redispatching the most economic and effective resources to manage network congestion.

In addition, there are two other key advantages to LMP markets versus TLR procedures as congestion management regimes. First, LMP markets proved more transparent and efficient price signals reflecting the presence of transmission congestion. Second, the central dispatch that occurs under an LMP market allows the transmission network to be more fully utilized and increases the RTO's control over network flows.

Real-time LMP markets are dispatched multiple times each hour (as often as every 5 minutes), continuously modifying the generator dispatch levels and associated network flows. This allows flowgates to be operated more closely to their limits. In addition, when flows do approach the limit, the LMP market will quickly and effectively redispatch generation to prevent the flows from exceeding the limit. Likewise when conditions change, the redispatch actions made in response to the constraint will be released much quicker than is possible under a TLR regime.

D. AFC Issues and Analysis

The Midwest ISO calculates AFC to process requests for transmission service and to indicate to participants the amount of unreserved firm and non-firm capability that exists on each flowgate. The analytic approach for calculating AFC values is comparable to the approach used by other transmission providers to calculate ATC values. ATC values correspond to the available capability between two locations (i.e., over a "contract path"). Alternatively, AFC values represent the capability available on a particular transmission facility or group of closely-related facilities. Hence, a limitation on one flowgate could limit the ATC value for many contract paths. Likewise, the reservation of service over a particular contract path will effectively use the AFC on many flowgates.

The Midwest ISO's AFC calculations involve a complicated process, including the use of multiple models to evaluate different time horizons, and the forecasting of generation, load, and loop flows from other systems. In addition, the Midwest ISO must make assumptions regarding the utilization of existing transmission reservations. For example, in assessing AFC in advance of scheduling for the operating hour, the Midwest ISO must make assumptions regarding how much of the reserved transmission on the flowgate will be scheduled.

The Midwest ISO continues to invest considerable time and effort on AFC improvements, both internally and cooperatively with participants through the AFC Working Group. The improvements have been focused on increasing the quality of data provided by members, increasing the accuracy of transmission system modeling, and improving the forecasting of generation and load.

We do not expect the AFC values to be completely accurate because the AFC models rely on inputs that have some degree of uncertainty (e.g., forecast loads, generation, and other factors). In addition, AFC calculations are affected by conservative assumptions regarding system conditions.[11]

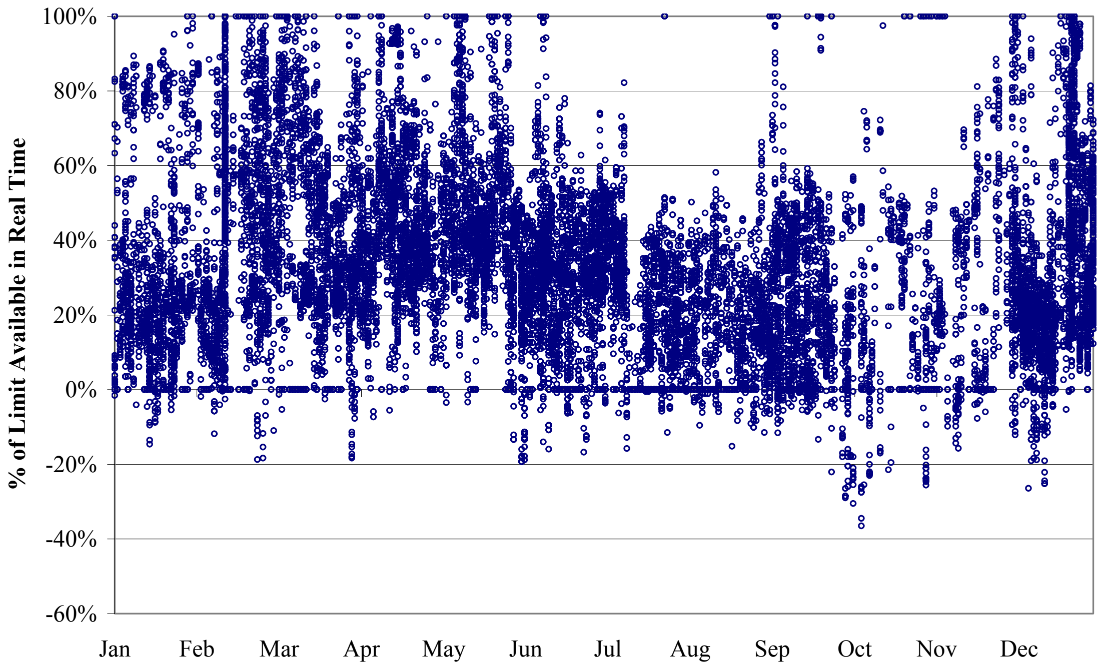
To assess the accuracy of the AFC values, we have conducted an analysis of the AFC values relative to the physical capability of the flowgates. The analysis focuses on hours when Midwest ISO posted zero AFC for non-firm hourly point-to-point service on a flowgate. Hours with zero AFC are studied because they likely affect trading in the Midwest by causing short-term service requests to be refused, and by signaling to participants that capability is unavailable.

To perform our evaluation of short-term AFC values, we calculated the percentage of flowgate capability that is physically available in real time (accounting for Transmission Reliability Margin) during hours when the hourly non-firm AFC was posted as zero. There should be a close relationship between hourly non-firm AFC and the un-used physical capability of a flowgate because it is calculated and posted close to the operating

11 In estimating firm AFC, reservations are assumed to be scheduled at a rate of 90 percent between their primary points while counter-flow reservations are assumed to be scheduled at only 10 percent. For non-firm AFC calculations, 100 percent of reservations between the primary points is assumed and 50 percent of the counter-flows. For firm reservations more than a month in the future, reservations are assumed to be scheduled at a rate of 85 percent between their primary points and counter-flow reservations are assumed to be scheduled at only 15 percent.

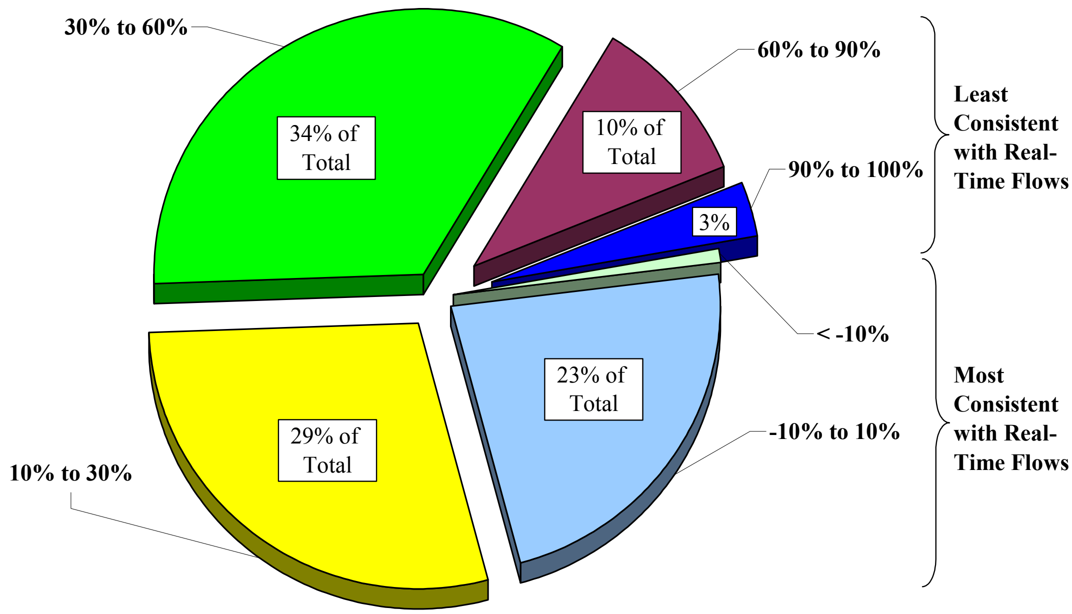
hour. In addition, it can be curtailed if necessary during the hour since it is non-firm. Figure 28 shows the scatter plot of these hourly values for 2003.

Figure 28: Percent of Flowgate Limit Physically Available in Real Time during Hours with Zero AFC



This figure shows a wide variance in the unused physical capability of the flowgates. If the AFC values accurately reflected the physical capability of the flowgates, the points would be clustered close to zero, distributed evenly around the horizontal axis at zero. However, the figure shows the average amount of capability available on the flowgates in hours with zero hourly non-firm AFC is 33 percent. To further evaluate these results, Figure 29 shows this data in a pie chart to show how these hourly results are distributed.

Figure 29: Real-time Flows relative to Flowgate Limits
Distribution of Hours with Zero AFC -- 2003



Each section of the figure represents a group of hours that have a common proportion of physical flowgate capability actually available in real-time. The top part of the chart in the figure represents the hours when the flows were least consistent with AFC (i.e., those hours when substantial physical capability was available). The bottom part represents hours when the flows were most consistent. For instance, the upper left portion of the chart indicates that in 34 percent of the hours when a flowgate had an hourly non-firm value of zero, the actual unused flowgate capability was between 30 percent and 60 percent of the physical limit. A detail of the data that comprises this figure is provided in the Appendix.

As the chart indicates, flows were relatively close to the limit in about one-half of the hours (physical availability was between 30 percent and -10 percent of the operating limit). Likewise, the flowgates in question had more than 30 percent of the physical capability available in approximately one-half of the hours studied. These results likely overstate the effect of the zero AFC postings because the Midwest ISO will often approve hourly non-firm service in these hours, utilizing some of the capability in real-time that was posted as being unavailable.

Nevertheless, it is important to continue to improve the AFC values and make them as accurate an indicator of available capability as possible. Accordingly, the Midwest ISO made some improvements in the calculation of the hourly non-firm AFC values in 2003. In May, the Midwest ISO restored hourly AFC quantities associated with daily and longer-term reservations that were not scheduled by the scheduling deadline. In December, the Midwest ISO began using the state estimator information to improve their short-term AFC models. Based on our review, these improvements have not completely resolved these issues. Hence, we recommend the Midwest ISO seek to more fully utilize the state estimator results and continue to investigate other initiatives to increase the accuracy of the AFC values.

VI. Market Power Analysis

In Section II we presented HHI statistics for each of the five Midwest ISO sub-regions. As explained in that section, relying only on basic market concentration statistics is not a reliable means to evaluate potential market power in wholesale electricity markets. In particular, it provides little insight regarding the existence or extent of locational market power associated with transmission congestion.

The competitive analysis presented in this section is an analysis we conducted in conjunction with developing the market power mitigation measures that were filed in March 2004. We present some of the key findings here because it provides important information regarding the potential for local market power in the Midwest ISO region.

A. Description of Methodology and Assumptions

Our analysis of locational market power focuses on areas that were frequently congested and which have one or more pivotal suppliers. The analysis is conducted for all Midwest ISO flowgates that had measurable congestion during the two years of the study (2002-2003). The frequency of congestion was measured based on the frequency of TLR events of level 3 and above – the level at which transaction curtailments are initiated. We also used the FGMT data and detected congestion when flows on the flowgate were "close" to the flowgate limit.

A supplier is pivotal when the output of some of its resources must be increased or decreased to resolve a binding transmission constraint on a flowgate. More precisely, a supplier is pivotal when the supplier can cause or sustain a binding constraint even when its rivals' generating resources are fully redispatched to relieve the congestion. This is determined by utilizing transmission load flow cases reflecting a variety of market conditions. For our study, the load-flow cases used to produce the inputs are four AFC cases for 2004: February, April, August, and November. These load-flow cases are used to produce the: (1) Generation-Shift Factors ("GSFs") relative to each potentially-constrained flowgate for all Midwest ISO and relevant non-Midwest ISO generators; (2) base loadings of generating resources; and (3) the base flows on each flowgate.

GSFs indicate the portion of a unit's output that flows over the flowgate. Once GSFs are determined for each generator, the effects of each supplier's resources on the flowgate can be calculated. A supplier is determined to be pivotal if it can dispatch its resources to increase the flow over the flowgate and create congestion that cannot be resolved by redispatching the rivals' generation to reduce the flow over the flowgate.

In the remainder of this section we describe the details of this process. We first discuss GSFs and explain their role in identifying suppliers' impact on flowgates.

1. Generation Shift Factors

A GSF is specific to a generator and a flowgate – it indicates what portion of the generator's output will flow over the flowgate. A positive GSF indicates that incremental production from the unit will increase the flow on the flowgate (i.e., congestion on the flowgate is decreased by reducing the unit's output). A negative GSF indicates that incremental production from the unit will create a "counter-flow" on the flowgate so that congestion is reduced on the flowgate by increasing output from such a generator. Likewise, a generator with a negative GSF can create congestion on the flowgate by reducing its output.

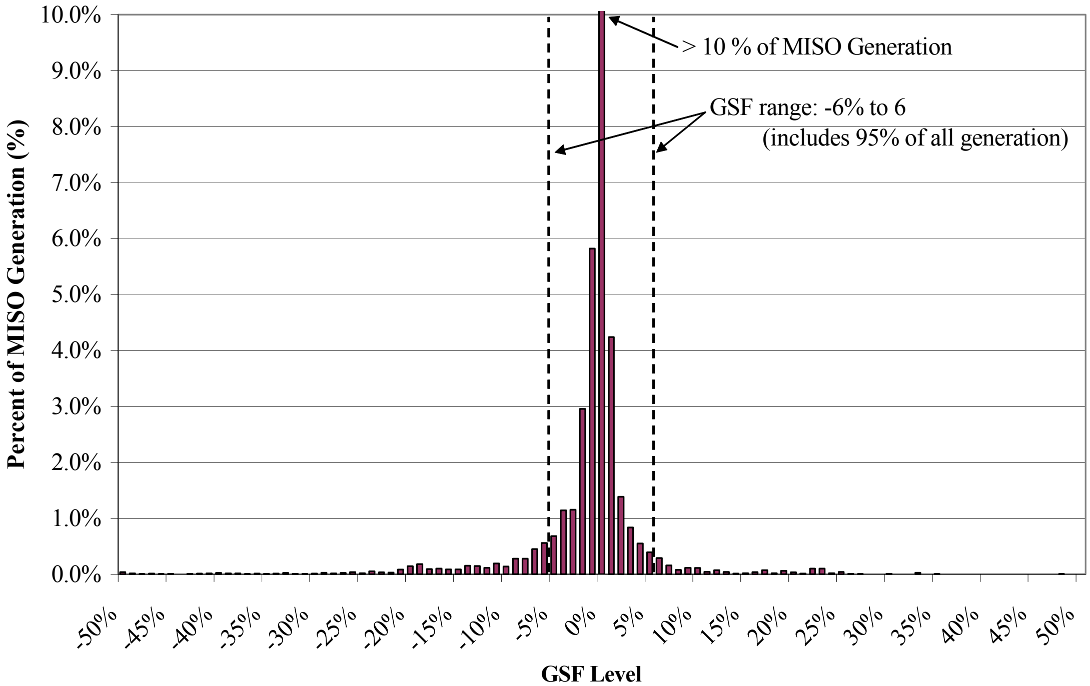
The GSFs used in our analysis are estimated from the Midwest ISO AFC Load Flow Case for four seasons in 2003: February, April, August, and November. The load flow cases were processed using the PowerWorld Transmission Simulation Model.[12] The simulation allows us to measure the increase in flows over a flowgate associated with incremental output from a generator.[13]

12 PowerWorld Simulator, Version 9.0, PowerWorld Corporation.

13 In simulating the power flows, we increase the output of the generator being evaluated and make a corresponding reduction in output across all other generators in the case. To ensure the GSFs are not biased based on the locations of the other generators, we shift all of the GSFs for the flowgate such that the median GSF value equals zero.

GSFs are smaller for generators that are located more electrically distant from a flowgate (i.e., further physical distance or connected over lower-voltage facilities). Therefore, most generators will have only a minimal impact on any given flowgate. To illustrate this point, Figure 30 shows the distribution of all units' GSFs across all of the major Midwest ISO flowgates.[14]

Figure 30: Distribution of Generation Shift Factors All Flowgates



As the figure indicates, more than 95 percent of the generating units have GSFs between 6 percent and -6 percent. While the data in this figure indicates a tight distribution around zero for the average of all flowgates, the distribution varies substantially among individual flowgates. As an example, consider the distribution of GSFs for the flowgates shown below in Figure 31 and Figure 32. Figure 31 shows the GSF distribution for the flowgate defined as the Albers-Paris 138 kV bus for a contingency on the Wempletown-Paddock 345 kV bus. Figure 32 shows the distribution of GSFs for the Arnold-Hazelton 345 kV bus.

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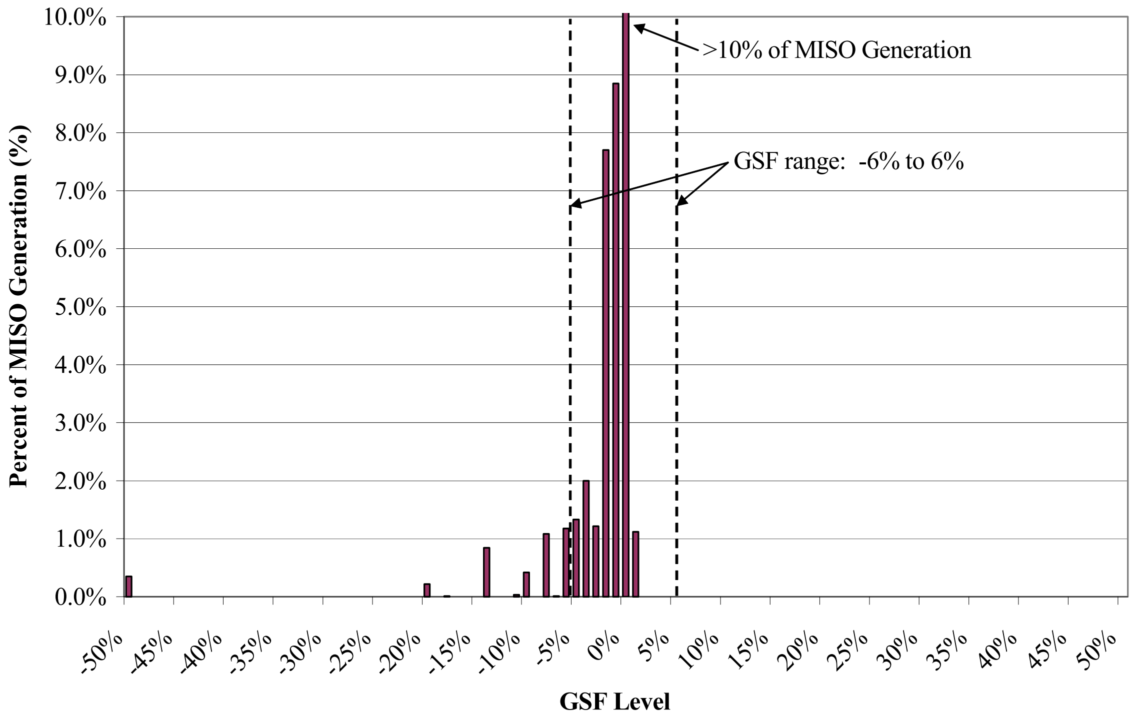
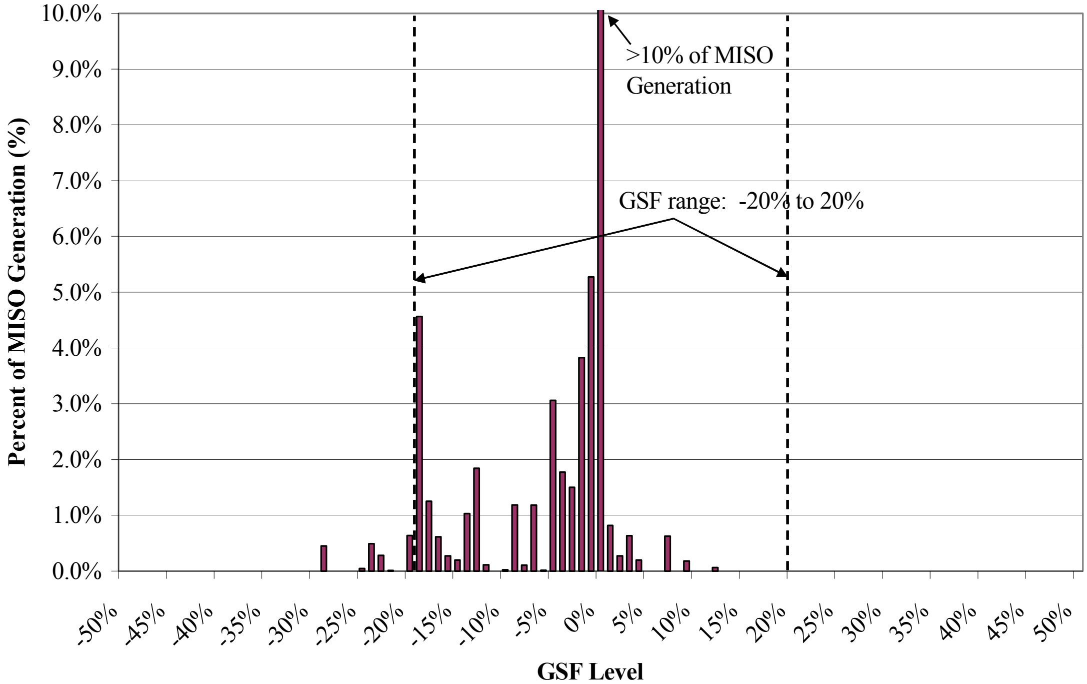
14 These flowgates are those facilities that tend to experience congestion in some hours during the year or would experience congestion but for measures taken to avoid it. These are also the flowgates that are closely monitored by NERC for reliability purposes.

Figure 31: Distribution of Generation Shift Factors Alber-Paris for Wempletown-Paddock 345 kV



Comparing the two distributions, it is clear that the distribution in Figure 31 is much tighter than the distribution in Figure 32. This is due in part to the fact that the Alber-Paris flowgate is a lower voltage facility (138 kV) than the Arnold-Hazelton flowgate (345 kV). The physical properties of electrical networks cause higher shares of the power flows to flow over higher-voltage facilities. Therefore, more units will exhibit higher GSFs for higher-voltage facilities, all else equal. A lower-voltage facility will tend to carry large portions of a unit's output when the unit is located relatively close to the facility.

Figure 32: Distribution of Generation Shift Factors Arnold-Hazelton 345 kV



The units that have GSFs are close to zero are less meaningful from a market power perspective than the units with higher GSFs because the units with GSFs close to zero will have negligible impacts on a flowgate. In addition, units with very low GSFs tend to be electrically distance from the flowgate. Using these resources to create substantial flows or relief on a flowgate would tend to require extraordinary shifts in generation that would likely be precluded by other network constraints or obligations to serve load. For these reasons, we exclude units with GSFs between 2 percent and -2 percent from the analysis.

2. Pivotal Suppliers

The analysis was conducted on 121 flowgates that have been the source of congestion over the past two years. Each Midwest ISO supplier is tested as a potential pivotal supplier on each flowgate. For each candidate pivotal supplier and each individual flowgate, we evaluate the candidate pivotal supplier's impact on a flowgate by increasing the output on its units that have positive GSFs and decreasing the output on units with negative GSFs. The units with positive GSFs are increased from the unit's *base flow* to the unit's *maximum output*. Both the base flow and the maximum output are given in the

Midwest ISO seasonal AFC case. Any of the supplier's units with a positive GSF that are turned off in the AFC Case are turned on, and their output is assumed to be maximum output. The candidate pivotal supplier's units with negative GSFs are decreased from their base flow to zero (i.e., they are turned off).

The changes in a candidate pivotal supplier's output together with the GSFs indicate the increased flow on the tested flowgate. If the increased flow causes the constraint to bind (i.e., flows exceed the operating limit), then we test the impact on the flowgate of all other suppliers to see whether the other suppliers' counterflows are sufficient to relieve congestion on the flowgate. This is modeled by decreasing the output on these other suppliers' generators that have positive GSFs and decreasing the output on the generators that have negative GSFs.

These counterflows are calculated in a manner similar to the calculation of flows for the candidate pivotal supplier, with two important differences. The first difference is that the output of other suppliers is changed in a manner that respects the balance of load and resources on the system. More precisely, if the candidate pivotal supplier achieved the maximum flow on the flowgate by decreasing output on a net basis, then the initial response of the other suppliers is to increase output on units with negative GSFs until the decremental output of the candidate pivotal supplier is off set. In doing this, the units with the greatest impact are applied first. After the system is "balanced" using this procedure, the remaining suppliers change their output in a manner to maintain system balance. This is done by matching decreases in output on other suppliers' units that have positive GSFs with increases in output on other suppliers' units that have negative GSFs.

The second difference between how the candidate pivotal supplier is treated and how all other suppliers are treated relates to the range of output over which units can be dispatched. Recall the candidate pivotal supplier changes from base flow to either maximum output (for positive GSF units) to zero output (for negative GSF units). For all other suppliers, no units at zero output are increased – i.e., no units are turned on if they are off in the AFC case; likewise, no units that are turned on are turned off.

Instead, only units that are online in the AFC case are used in simulating counterflows. These units are permitted to change output between the minimum and maximum output. These restrictions rest on the premise that a pivotal supplier seeking to exercise market power has the opportunity to plan in advance, including committing and decommitting units for the purpose of creating congestion. Rival suppliers on the other hand would generally only be able to react to the pivotal supplier in real time by redispatching online units.

If the total counterflows created by the other suppliers are not sufficient to offset the flows created by the candidate pivotal supplier, then the candidate pivotal supplier is indeed pivotal on that flowgate.

B. Summary of Results

Table 7 and Table 8 show each of the flowgates with at least one pivotal supplier in the four monthly cases. Table 7 shows flowgates affecting imports into or transfers within WUMS. Table 8 shows other flowgates within Midwest ISO or PJM which cause a supplier to be pivotal. For each of the flowgates, the tables indicate the average number of constrained hours over the past two years, the number of pivotal suppliers, the pivotal supplier ratio (average amount by which the pivotal suppliers can overload the flowgate as a percent of the flowgate limit), and the required decrement ratio (the minimum percentage that any pivotal supplier must reduce its base generation to cause congestion).

The pivotal supplier ratio is important because it produces an indication of how much control the supplier has over a given flowgate's flows. A very high pivotal supplier ratio would suggest that the supplier may have the ability to cause the constraint to bind under a broader array of market conditions. The required decrement ratio is also a very useful statistic because it shows the portion of a pivotal supplier's portfolio that would have to be withheld to cause the constraint to bind. A high required decrement ratio would indicate that the strategy will likely be more visible and more costly to implement. If the entity had load to serve, it would have to purchase replacement power; and if not, it would have to forgo the opportunity to produce electricity profitably. Alternatively, a low required decrement ratio would generally suggest more severe market power, all things equal.

Table 7: Pivotal Supplier Analysis Results by Flowgate: WUMS Flowgates

		February 2004 Case			April 2004 Case			August 2004 Case			November 2004 Case		
Flowgate	Constr. Hours	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio
Flow South	1459	3	98%	0%	1	20%	0%	1	86%	0%	1	50%	0%
Highway V - Preble 138 (flo) Lost Dauphin - Red Maple	181	2	52%	0%	1	11%	0%	2	26%	0%	1	15%	23%
HIGHWAYV-PREBLE+N APPLTN-WHITE CLAY	115	2	43%	0%	1	15%	0%	2	20%	0%			
N Appleton-Wh Clay 138 for Stiles-Pulliam 138	34	3	26%	0%	1	14%	0%	1	30%	0%	1	18%	0%
STILES4-PULLIAM 138+STILES5-PULLIAM 138	279	2	30%	0%	1	21%	0%	1	30%	0%	1	5%	0%
Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains	1883	2	97%	0%				1	53%	0%	1	30%	0%
Stiles-Amberg 138 for Morgan-Plains 345	40	3	47%	0%	1	56%	0%	1	108%	0%	1	23%	0%
Stiles-Pioneer 138 for N.Appl-WhiteClay138	799	2	32%	0%	1	14%	0%	1	45%	0%	1	5%	0%
Green Lk-Roeder 138 for N Appleton-RoR 345	17							2	56%	61%			
N.Appleton-LostDauphin 138 for Kewaunee 345-138 TR	466				2	9%	0%	1	17%	20%			
KEWAUNEE 345/138 XFMR	8				1	1%	0%						
KEWAUNEE XFMR+KEWAUNEE-N APPLETON	702				1	11%	0%						
2221 Zion-PlsP for 17101 Wemp-Pad	12	1	4%	97%				1	96%	47%	1	5%	95%
Albers-Paris138 for Wemp-Padock 345	634	1	10%	12%	1	18%	0%	3	22%	22%	1	23%	20%
Blackhwk-Cor X54 for Paddock-ROR X39 138	233	2	29%	0%	2	12%	80%	2	45%	0%	2	28%	0%
Cassvl-NED 161 for Wemp-Paddock 345	22	1	28%	0%	1	27%	0%	2	35%	36%			
EAU CLAIRE-ARPIN 345 KV	224	1	1%	96%	1	4%	77%	2	13%	19%	2	10%	0%
LOR5-TRK RIV5 161KV/WEMPL-PADDOCK 345KV	600	1	13%	3%	1	19%	0%	4	29%	2%	1	17%	16%
NELSON DEWEY XFMR+WMPLETOWN-PADDOCK	6	1	38%	0%	1	39%	0%	2	44%	0%	1	65%	0%
Paris-Burlington 138 (flo) Wempletown-Paddock 345	26	1	1%	43%	1	5%	0%	2	7%	10%	1	16%	14%
PleasPr-Racine 345 for Wemp-Pad 345	15	1	20%	40%	1	19%	33%	1	62%	23%	1	27%	29%
Salem 345/161 flo Wempletown-Paddock 345	535	1	1%	99%				2	20%	66%			
WEMPLETOWN-PADDOCK 345 KV	9							1	10%	71%			
PADDOCK XFMR 1 + PADDOCK-ROCKDALE	377							2	26%	17%			
Russel-Rockdale 138/Paddock-Rockdale 345	318							2	1%	11%			
Kenosha-Albers 138 for Wempletown-Paddock 345	8							1	13%	56%			
Arnold-Hazelton 345 for Wemp-Paddock 345	107							1	54%	71%			

Table 8: Pivotal Supplier Analysis Results by Flowgate: Other Flowgates

		February 2004 Case			April 2004 Case			August 2004 Case			November 2004 Case		
Flowgate	Constr. Hours	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio	# of Pivotal Suppl.	Pivotal Supplier Ratio	Reqd. Dec Ratio
Blue Lick 345/161 XFMR-Baker-Broadford	243	2	13%	0%	1	13%	0%	2	23%	0%	1	4%	2%
Blue Lick-Bullit Co 161 (flo) Clifty Creek-Trimble Co	104	1	14%	0%	1	12%	0%	1	3%	18%	1	3%	0%
Blue Lick-Bullitt Co 161 flo Baker-Broadford 765	17	1	2%	18%									
Brown South-Fawkes 138 kV	31	1	36%	28%				1	55%	20%			
Gibson-Petersburg 345 flo Gibson-Bedford 345	16	1	12%	42%				1	0%	99%	1	1%	85%
Lakefield-Fox lake 161 (flo) Lakefield-Wilmarth 345	131	2	53%	35%	2	76%	23%	1	106%	47%	1	40%	59%
Lakefield-Fox Lk 161 for Lakefield-LGS 345	248	2	53%	35%	2	76%	23%	1	106%	46%	1	33%	64%
Paddys West-Paddys Run 138 (flo) Cane Run 138	14	1	34%	0%	1	19%	0%	1	84%	0%	1	53%	0%
ROCKY RUN -NORTHPT+WESTON-ROCKY RUN	593	1	79%	0%	1	57%	0%	1	103%	3%	1	86%	2%
Wisdom-Triboji 161 flo Raun-Lakefield 345	46	1	19%	86%	1	14%	90%	1	109%	55%			
05MARYSV 05E LIMA 345-MARYSV SWLIMA 345	11							1	5%	86%			
BentnHrbr-Palisades345/Cook-Palisades345	6							1	9%	89%			
X59 Christiana-Kegonsa 138 for F1 Christiana-Fitchburg	57							1	6%	38%			
Arnold - Hazleton	87							1	44%	75%			
Salem 345/138 Quad Cities-Sub 39	285							2	13%	73%			
Salem 345/161 for Quad-Sub 91 TR	228							2	14%	72%			
Arnold-Vinton 161 for D.Arnold-Hazelton 345	610							1	40%	73%			
Sub 56(Davnprt)-E.Calamus161 for Quad-RockCr345	225							2	15%	67%			
10ABBRWW 138 14HENDR4 138 1	43				1	26%	0%						
Dysart-Washburn 161 for D.Arnold-Hazelton 345	137				1	1%	100%	2	34%	65%			
Hills 345/161 Xfmr flo Tiffin-Duane Arnold 345	183							2	5%	0%			
MHEX_S	60							1	1%	0%			
Sub K/Tiffin-Arnold 345kV	100							1	16%	89%			
S1226-Tekamah 161kV flo S3451-Raun 345kV	253							1	10%	92%			

Of the 121 flowgates studied, the tables show the 51 flowgates that have at least one pivotal supplier in one of the four cases. More than half of these 51 flowgates affect flows into or within WUMS, which are presented together in Table 7. Twenty-eight of the 121 flowgates studied have more than one pivotal supplier in one of the cases, while 19 of the flowgates have at least one pivotal supplier in all four cases. The pivotal suppliers often do not need to reduce their overall output, which increases the market power concern. Indeed, 24 of the 51 flowgates show that at least one of the pivotal suppliers would not have to reduce its output in one of the monthly cases.

Of the flowgates that exhibit one or more pivotal suppliers, generally only flowgates affecting flows into or within WUMS are frequently congested. We concluded from this analysis that there are significant locational market power issues associated with the transmission constraints in the WUMS region.

To address market power concerns more broadly, we have worked closely with market participants and the Midwest ISO to develop mitigation measures that will be implemented with the Day 2 LMP markets in the Midwest, which were filed with FERC in March 2004. These measures address potential economic withholding, physical withholding, and other strategies a supplier with market power could potentially use to exercise market power. To address the more severe forms of locational market power that can exist in chronically-constrained areas, the proposed mitigation measures would be applied differently in areas designated as “narrow constrained areas”. Based on the results presented above, we have designated WUMS and North WUMS as narrow constrained areas for purposes of the market power mitigation measures. These measures will ensure that the customers in these areas enjoy the benefits of efficient wholesale electricity markets in Day 2.

Appendix

Available Physical Capability when Zero AFC Posted

Flow Gate Description	Control Area	Total Count	-10% to 10%	10% to 30%	30% to 60%	60% to 90%	Over 90%
Paddock 345/138 XFMR (flo) Paddock-Rockdale 345	ALTE	319	222	87	10		
Rockdale 345/138 T22 (flo) Paddock 345/138 XFMR	ALTE	133	128	1	3	1	
Nelson-Dewey 161/138 XFMR (flo) Wempletown-Paddock 345	ALTE	8				8	
Nelson Dewey 161/138 XFMR (flo) Eau Claire-Arpin 345, Wien-T Crnrs	ALTE	7				7	
Paddock Blackhawk 138 (flo) Paddock-Rock River 138	ALTE	12		1	10	1	
Christiana-Kegonsa 138 (flo) Columbia-N Madison 345	ALTE	7				7	
Rockdale-Lakehead 138 (flo) Eau Claire-Arpin 345, Wien-T Crnrs	ALTE	225		107	118		
Blackhawk-Colley Rd 138 (flo) Paddock-Rock River 138	ALTE	369	64	296	9		
Russel-Rockdale 138 (flo) Paddock-Rockdale 345	ALTE	187	121	55	11		
N Lake Geneva Tap-Lake Geneva 138 (flo) Wempltown-Paddock 345	ALTE	11			11		
Green Lake-Roeder 138 (flo) N.Appleton-Rocky Run 345	ALTE	79	10	21	44	4	
Christiana-Kegonsa 138 for Christiana-Fitchbrg 138	ALTE	10	2		8		
Cassville-Nelson Dewey 161 (flo) Wempletown-Paddock 345	ALTE,DPC	120	54	59	7		
Eau Claire-Arpin 345	ALTE,NSP,WEC,WPS	96	15	46	18	13	4
.SI (Minnesota,Wisconsin Stability Interface)-*	ALTE,WEC,WPS,NSP	55	29	10	16		
Eau Claire-Arpin 345 (flo) Prairie Island-Byron 345	ALTE,WPS,WEC,NSP	7				7	
Poweshiek-Reasnor 161 (flo) Montezuma-Bondurant 345	ALTW	984	689	115	129	44	7
Lore-Turkey River 161 (flo) Wempletown-Paddock 345	ALTW	1387	311	188	744	130	14
Adams 345/161 XFMR (flo) Adams-Hazleton 345	ALTW	7			7		
Rock Creek 345/161 XFMR (flo) Quad Cities-Sub 91 345	ALTW	7			7		
Salem 345/161 XFMR (flo) Cordova-Sub 39 (E.Moline) 345	ALTW	125	21	89	15		
Tiffin-Duane Arnold 345 (flo) Montezuma-Hills 345	ALTW	85	6	58	21		
Arnold-Vinton 161 (flo) Hazleton-Arnold 345	ALTW	763	613	116	28	6	
Sub 56 (Davenport)-E. Calamus 161 (flo) Quad Cities-Rock Creek 345	ALTW	393	197	118	11	67	
Lakefield-Fox Lake 161 (flo) Lakefield-Lakefield Generation 345	ALTW	376	155	77	66	6	72
Dysart-Washburn 161 (flo) D.Arnold-Hazelton 345	ALTW	159	83	63	9		4
Turkey River-Cassville (flo) Wemp-Pad	ALTW,CE	172	1	8	147	16	
Speed 345/138 XFMR (flo) Ghent-W. Lexington 345	CIN	7				7	
Gibson 345/138 (flo) Gibson-Petersburg 345	CIN	11				11	
Cayuga-Veedersburg 230 (flo) Cayuga-Frankfort 230	CIN	7			7		
New London-Frankfort 230 (flo) Cayuga-Veedersburg 230	CIN	7			7		
Gallagher-Paddys West 138 (flo) Clifty Creek-Trimble Co. 345	CIN,LGEE	91		10	33	40	8
Speed-Northside 138 (flo) Clifty Creek-Trimble Co. 345	CIN,LGEE	241	6	12	22	120	81
Oakland-Toyota 138	CIN,SIGE	44			26	17	1
Merom-Dresser 345	HE,CIN	7			6	1	
Merom-Gibson 345	HE,CIN	7			4	3	
Worthington-Bedford 138	HE,CIN	7				7	
IMO-MECS	IMO	143		7	46	42	48
Petersburg-Thompson 345	IPL	7		7			
Petersburg 345/138 XFMR (East)	IPL	14	2		10	2	
Petersburg 345/138 XFMR (East) (flo) Petersburg 345/138 XFMR (W)	IPL	298	71	166	60	1	
Petersburg-Oakland City 138	IPL,CIN	29	1	1	2	18	7
Petersburg-Lost River 345	IPL,CIN	7				7	
Petersburg-Gibson 345	IPL,CIN	39	29	1			9
Speed-Northside 138 (flo) Speed-Ghent 345	LGEE	7					7
Brown North-W. Lexington 345	LGEE	594	129	149	221	13	82
Pineville 500/345 XFMR	LGEE	3		2	1		
Ghent-W.Lexington 345 (flo) Baker-Broadford 765	LGEE	29		15	7	7	
Brown South-Fawkes 138	LGEE	407		63	333	11	
Blue Lick-Bullit County 161 (flo) Ghent-W Lexington 345	LGEE	2735	374	1301	1032	28	
W.Lexington-Brown 345 (flo) of Baker-Broadford 765	LGEE	249	1	108	125	15	
Paddys West-R. A. Gallagher 138	LGEE,CIN	12	3	2		5	2
Brownstown-Monroe 345 1 (flo) Monroe-Wayne 345	MECS	7				7	
Monroe-Wayne 345 (flo) Monroe-Brownstown 345 1	MECS	55				1	54
MECS-IMO	MECS	1316	79	104	513	496	124
Eau Claire-Arpin 345 (flo) Wempletown-Paddock 345	NSP,ALTE,WEC,WPS	14	4	3		7	
Culley-Grandview 138	SIGE	176	37	78	47	14	
Newtonville 161/138 XFMR	SIGE	14				12	2
Cato Tap-Petersburg 138	SIGE,IPL	7				7	
Newtonville-Cloverport 138 (flo) Coleman-National Aluminum 161	SIGE,LGEE	486	95	128	172	87	4
Albers-Paris 138 (flo) Wempletown-Paddock 345	WEC	673	447	187	39		
Stiles-Pioneer 138 (flo) N.Appleton-White Clay 138	WEC	525	30	192	288	15	
Stiles-Amberg 138 (flo) Morgan-Plains 345	WEC	32		5	22	5	
Pleasant Prairie-Racine 345 (flo) Wempletown-Paddock 345	WEC	18	8	3	7		
Amberg-Plains 138 (flo) Plains-Morgan 345	WEC	33				27	6
N Appleton-Lost Dauphine 138 (flo) Kewaunee 345/138 XFMR	WEC	1635		56	1087	458	34
Kewaunee 345/138 XFMR (flo) Kewaunee-N. Appleton 345	WPS	1318	20	853	445		
Highway V-Preble 138 (flo) N Appleton-White Clay 138	WPS	153	113	33	7		
Highway V-Preble 138 (flo) N Appleton-Mason St 138	WPS	42	11	29	2		