2002 STATE OF THE MARKET REPORT

MIDWEST ISO

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Independent Market Monitor
for the Midwest ISO

May 2003

2002 State of the Market Report

Midwest ISO

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I. Executive Summary

This report evaluates the state of the wholesale electricity markets in the Midwest during 2002. The Midwest ISO ("MISO") began operations in 2002, which included the introduction of regional transmission service and reliability coordination for the Midwest ISO region.

The Midwest ISO is not yet operating energy and ancillary services markets, although it plans to introduce spot energy markets in Spring 2004 ("Day-2 markets"). These markets will allow the Midwest ISO to efficiently manage transmission congestion and set transparent market-clearing prices at each location on the network. Substantial portions of the market rules for the Day-2 energy markets were developed and filed at FERC during 2002.

Because the Midwest ISO does not yet operate spot energy or ancillary services markets, the focus of this report will be very different than the State of the Market reports issued by other ISOs or RTOs. This report assesses the characteristics and operations of the markets as they currently exist in the Midwest ISO region. The assessment will include an evaluation of the Midwest ISO's current operations to determine whether it is efficiently facilitating the current wholesale markets. The remainder of the report reviews and evaluates the market structure and proposed rules that will underlie the Day-2 energy markets. This section provides a brief summary of the conclusions and recommendations in the report.

Market Characteristics

The Midwest ISO region, including entities that have announced that they will join the Midwest ISO this year, contains over 150,000 MW of generating capacity. Much of this capacity is relatively new, added after the price spikes that occurred in the region during 1998 and 1999. This investment has caused the reserve margin in the Midwest ISO area to rise to approximately 20 percent on average -- substantially higher than historical levels and FERC's proposed minimum reserve margin requirement.

In four sub-regions within the Midwest ISO (not including WUMS), the reserve margin ranges from 19 percent to 27 percent, which exceeds historical levels for the region. The reserve margin in WUMS is lower than other regions within the Midwest ISO, and the market concentration is relatively high.

The market concentration in WUMS, as measured by the HHI statistic, is 2700. The market concentration in most of the Midwest ISO sub-regions is in the moderate range from 1000 to 1800. Although these concentration statistics provide some useful information regarding the structure of the market, they are not intended to be sufficient to draw reliable market power conclusions.

The generator fuel mix in the Midwest is dominated by coal-fired resources, accounting for 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. The Midwest region relies little on hydroelectric resources (less than 10 percent of the total capability) relative to other regions.

Wholesale Market Prices in 2002

Bilateral wholesale energy prices were primarily correlated with load levels (as expected due to the lack of storage), with the highest prices occurring during peak periods. However, daily prices increased by more than 20 percent from February to December, influenced largely by increases in natural gas and fuel oil prices. These price increases were moderated by decreases in coal prices through 2002, which play an important role in setting prices during lower load periods.

Our analysis assessing how accurately prices reflected transmission congestion during 2002 indicated 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 LMP spot markets on Day-2, which should provide more accurate and transparent price signals. Because these signals direct both short-term generation commitment and dispatch decisions and long-run investment and retirement decisions, the Day-2 spot markets promise substantial efficiency benefits for the region.

Disposition of Transmission Service Requests and AFC Values

The report analyzes requests for and approvals of transmission service and find both have risen sharply from February to December 2002. In particular, approved non-firm requests increased by 173 percent and approved firm requests increased by 129 percent. The increase in approved reservation requests was caused primarily by two factors. First, discounts for transmission service offered by the Midwest ISO for non-firm transmission service increased through the year. Second, improved modeling of available flowgate capability ("AFC") made more capacity available.

Additional improvements in AFC calculation are planned for 2003 and should further increase the availability of flowgate capability. The report recommends that the Midwest ISO investigate specific means of improving the coordination of hourly AFC values with actual power flows on the flowgates to improve the accuracy of the AFC values and, ultimately, the utilization of the transmission system.

Transmission Utilization: Congestion Management and TLRs

The report evaluates the TLRs invoked in 2002 to manage constraints on Midwest ISO flowgates. Based on this analysis, we find that the Midwest ISO has invoked TLRs in a consistent and justifiable manner. During the time period studied in the report, TLRs occurred in only 1.5 percent of the hours when the flow on the relevant flowgate was less than 95 percent of flowgate capability. Additionally, in less than 0.2 percent of the hours the power flow was greater than the flowgate limit without a TLR being invoked. Taken together, these results indicate that the TLR process has been well-managed by the Midwest ISO during 2002.

The report also evaluates the effectiveness of the TLR process in managing congestion. This evaluation shows that the TLR procedures are substantially inferior to the economic dispatch process that will occur under the Day-2 LMP markets. On average, almost three times as many transactions are curtailed as would be required to be economically redispatched to provide the necessary relief on the flowgate. This strongly supports the move to LMP spot markets in the Midwest as a means to improve the efficiency with which network constraints are managed.

Pivotal Supplier Analysis

We provide updated results of the pivotal supplier analysis performed in 2002. A pivotal supplier is a supplier whose resources must be used to prevent a flowgate from becoming overloaded. This analysis is a precursor to the analysis that will need to be conducted to define Narrow Constrained Areas for purposes of the market power mitigation measures. Our analysis shows that there are a significant number of cases where the prices affected by certain flowgates may be subject to local market power by a pivotal supplier.

Market Development and Rules

The Midwest ISO filed the Midwest Market Initiative at FERC in 2002 and FERC approved the general framework. The central feature of the Market Initiative is a two-settlement locational spot market for energy. The proposed market framework is sound and will increase the efficiency of the power markets in the region considerably.

However, the rules associated with energy pricing at times when the system is in shortage require further development to ensure the markets send efficient price signals to support long-run investment. The report summarizes energy pricing provisions that we initially proposed in a memo to the Operating Reserves Task force that would apply during shortage conditions.

RTO Configuration and Coordination

Finally, the report provides an updated analysis of the RTO configuration in the Midwest, evaluating the potential seams between the Midwest ISO, PJM, and SPP. This analysis was originally conducted during the summer of 2002 when the former Alliance RTO companies announced their proposed RTO elections. At that time, AEP, Commonwealth Edison, Dayton Power & Light, and Illinois Power announced their intention to join PJM. First Energy, Ameren, and NIPSCo elected to join the Midwest ISO. FERC approved the elections with specific requirements on the development of the Joint and Common Market ("JCM") to address reliability and efficiency concerns.

The analysis in this report is updated to reflect changes in Midwest ISO's configuration, including the dissolution of the Midwest ISO-SPP merger and the subsequent decision of Illinois Power to join the Midwest ISO. We continue to find a high degree of electrical interaction between the Midwest ISO region and adjacent areas. Without sufficient coordination, this interaction raises significant efficiency concerns related to the locational prices and market dispatch, as well as potential gaming concerns. These concerns should not cause participants or policymakers to postpone the implementation of the LMP markets, but they do indicate the paramount importance of effective coordination between the RTOs through the JCM.

Based on our review of current JCM materials, the Midwest ISO, PJM, and SPP have worked to develop a TLR process that will allow TLRs to be used to effectively manage interactions between market and non-market areas. These provisions are known as the "market to non-market interface". This interface will be useful in the short-run before the RTOs are operating LMP energy markets adjacent to one another. In addition, it will continue to be useful over the longer-run for coordinating with adjacent non-RTO areas.

In addition to the market to non-market interface, the JCM anticipates a "market to market" interface. This interface will include the provisions to coordinate network flows and congestion management between adjacent areas operating LMP energy markets. The market to market interface has not yet been developed. The design and implementation of the interface will require significant time and resources and it may be needed as soon as Spring 2004. Therefore, the report makes specific recommendations regarding the design of the interface for the RTOs to consider that we hope will speed its development.

The recommendations for the market to market interface include real-time exchange of key pricing information that will allow the prices in each area to reflect its effects on network constraints in adjacent areas. The report does not provide a detailed plan for the interface, but only a starting point that we hope is useful to the RTOs in developing such a plan in consultation with the market participants.

II. Introduction

This report evaluates the state of the wholesale electricity markets in the Midwest during 2002. The Midwest ISO does not yet operate spot energy markets. These markets will be implemented in Spring 2004, which will allow the Midwest ISO to efficiently manage transmission congestion and set transparent market-clearing prices at each location on the network (i.e., locational marginal prices or "LMPs"). These markets have been generally referred to as the "Day-2 markets". However, while LMP markets are not yet operating, the Midwest ISO achieved intermediate objectives in 2002 as it began operations as a Regional Transmission Organization ("RTO").

In February, the Midwest ISO began selling transmission service in the Midwest, allowing participants to transact throughout the region at a single-rate pursuant to its FERC-regulated transmission tariff. In addition to administering the transmission tariff, the Midwest ISO's responsibilities include security coordination and various planning functions. Because the Midwest ISO does not facilitate centralized spot markets for energy or ancillary services, the focus of this report will be significantly different than the State of the Market reports from other RTOs or ISOs that operate spot markets. This report will focus on the region's supply and demand characteristics, the Midwest ISO's sale of transmission service, and the coordination of reliability in the Midwest. This report also provides a preliminary analysis of potential locational market power, prospective assessments of the electrical configuration of the Midwest ISO system, and the current state of the Day-2 market rules.

In December, two major FERC filings were made in furtherance of the introduction of the Midwest ISO markets. The first filing introduced the preliminary framework for the Day-2 markets, referred to as the Midwest Market Initiative, requesting a declaratory order validating the general approach being taken by the Midwest ISO (which was granted in February). Under the Initiative, substantial elements of the competitive energy markets are proposed to be operational at the end of March 2004. This phase of the initiative will introduce LMP spot energy markets and the associated markets for financial transmission rights.[1] The second filing proposed market power mitigation measures to address locational market power to be available once the LMP spot markets are operational. This plan was largely approved in March 2003.

While the current Midwest Market Initiative documents introduce substantial elements of the proposed market framework, other elements remain under development, including a resource adequacy mechanism, shortage pricing provisions, and a safety-net bid cap. The Midwest ISO will operate initially with approximately thirty control areas. The control areas will be responsible for committing sufficient generation to meet load and maintain required reserves for the following day and for sending automated signals to generators to follow load and regulate the frequency of the system in real-time. Shortly after the LMP spot markets are operational in Spring 2004, the Midwest ISO will introduce software changes to enable it to perform the generation commitment function. Later, operating reserve spot markets will be developed to efficiently select and compensate suppliers of operating reserves.

A major development in the planning for regional markets was the termination of the Midwest ISO merger with SPP in March 2003. However, the Midwest ISO and SPP will continue to work on critical market integration issues through the Joint and Common Market framework, which includes PJM as well. The ultimate goal of the initiative is to integrate the combined Midwest ISO/PJM/SPP region into a single coordinated LMP market structure. The planning for the Joint and Common Market is ongoing. Benefits derived from initial coordination provisions and "one-stop shopping" are to be realized by mid-2004. Final implementation of a single coordinated market is scheduled by the end of 2005. A major benefit of the Joint and Common Market initiative will be the amelioration of seams between the regions. This is particularly important in the Midwest because the regions have significant electrical interaction. Issues associated with the Joint and Common Market are addressed in more detail in Section VIII.

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1 While the Midwest ISO had anticipated implementation of a re-dispatch service for 2002 which would have expanded spot market trading for firm transmission capability, this was suspended and will be superceded by eventual implementation of the LMP spot markets.

While the development of the Day-2 markets under the Midwest Market Initiative will provide the long-run market framework for the Midwest, this report also focuses on the profile and operations of the markets as they currently exist in the Midwest ISO region. The wholesale market activity in the Midwest is currently occurs through bilateral spot and forward contracting using the Midwest ISO open-access transmission tariff to physically deliver power. Hence, the report assesses various aspects of the Midwest ISO's current operations to determine whether it has efficiently facilitated the current wholesale markets. In the remainder of the report, we examine the structure of the markets in the Midwest and the current state of the market rules that will underlie the Day-2 markets in the region.

The report is organized as follows. Section III examines the load and resource balances within the Midwest ISO, including capacity to import and export power over the primary transmission interconnections in the Midwest. Section IV analyzes general price trends in the Midwest and evaluates how efficiently these prices have revealed the presence of binding network constraints. Section V summarizes and assesses transmission operations and utilization during 2002. Section VI provides a preliminary analysis that was conducted during 2002 of potential local market power associated with individual transmission flowgates. Section VII addresses Midwest ISO LMP market rules, including recommendations in areas where development of the rules is ongoing. Finally, Section VIII analyzes the electrical configuration of the Midwest ISO transmission network and examines issues surrounding the Joint and Common Market proposed with the SPP and PJM.

III. Characteristics of Midwest Markets

As the March 2004 implementation of the locational spot markets approaches, it is valuable to evaluate the underlying supply and demand fundamentals of the Midwest markets. In this section of the report, we summarize load and generation within each area encompassed by the Midwest ISO region. We also examine transmission capacity within the Midwest ISO.

The Midwest ISO region is comprised of the transmission-owning utilities that have transferred control of their transmission facilities to the Midwest ISO, either as a signatory to the Midwest ISO open-access transmission tariff or as members of Independent Transmission Companies that are members of the Midwest ISO under Appendix I of the Midwest ISO Agreement. Both the open-access tariff and the Midwest ISO agreement have been filed with and approved by FERC.

For purposes of the analysis in this report, we include those transmission areas that are presently in the Midwest ISO, as well as areas served by transmission assets that are anticipated with reasonable certainty to be under Midwest ISO control by March 2004. Our analysis includes, for example, utilities that make up GridAmerica (i.e., FirstEnergy, Ameren, and Northern Indian a Public Service) who are anticipating joining this year. It also includes various other utilities that have indicated an intention to join pending resolution of certain regulatory and commercial issues (e.g., Nebraska Public Power District, Missouri Public Service).

We divide the Midwest ISO into the five sub-regions corresponding to the study regions used in the MAIN 2002 Summer Assessment. These subdivisions are useful in utilizing the transmission characteristics from the Summer Assessment with the generation and load statistics in each area. These five regions are:

(1) ECAR -- which represents the transmission-owning utilities in the NERC ECAR region that are members of the Midwest ISO;

(2) South MAIN -- which represents the transmission-owning utilities in the NERC MAIN region (including Illinois Power expected to join the

Midwest ISO this year and Utilicorp, but excluding Commonwealth Edison and excluding the WUMS utilities defined below);

(3) IOWA – which represents Mid American Energy Company and Alliant West;

(4) North MAPP which represents the transmission-owning utilities in the NERC MAPP region, (excluding those in IOWA but including Manitoba Hydro); and

(5) WUMS -- which represents 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 N. MAPP).

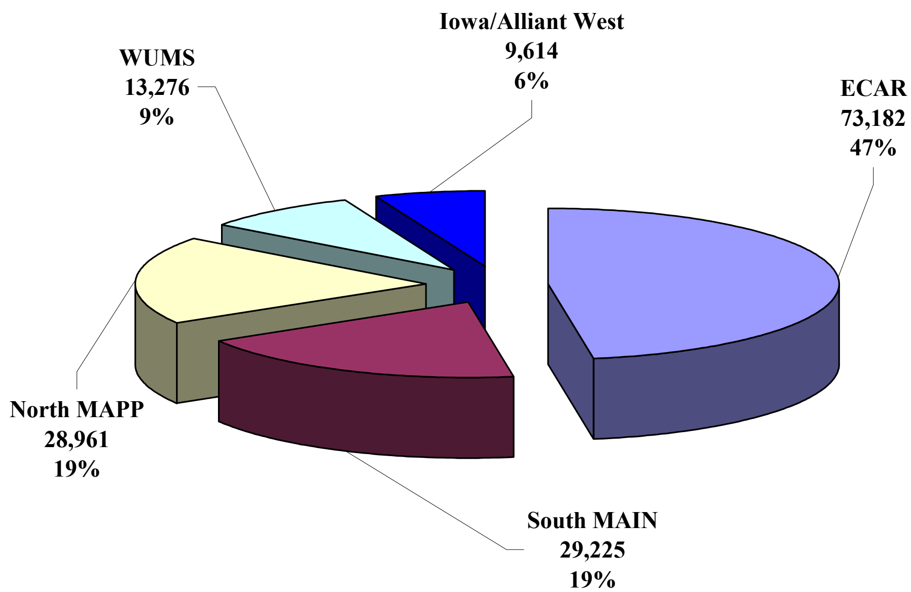
All loads and resources within the Midwest ISO are interconnected to the transmission facilities of one of the Midwest ISO transmission utilities within one of the sub-regions. There are over 300 distinct owners of generation resources in the Midwest ISO. These generators include large investor-owned 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 discussion using these sub-regions, it should be emphasized that these individual geographic areas should not be viewed as distinct markets. This is particularly true of the data presented below concerning market concentration in these sub-regions. Therefore, the concentration (or lack of concentration) within them is not dispositive regarding the relative competitiveness of the area. An accurate market power analysis would require substantially more investigation beyond simply calculating market shares and concentration statistics.

A. Supply and Demand Balance

Figure 1 shows the distribution of generating capacity within the five sub-regions. For the Midwest ISO altogether, the resources total about 155,000 MW. The ECAR sub-region is the largest, with almost one-half of the total Midwest ISO capacity. These figures include both current Midwest ISO members and those expected to join with relative certainty.

Figure 1
Geographic Distribution of MISO Capacity

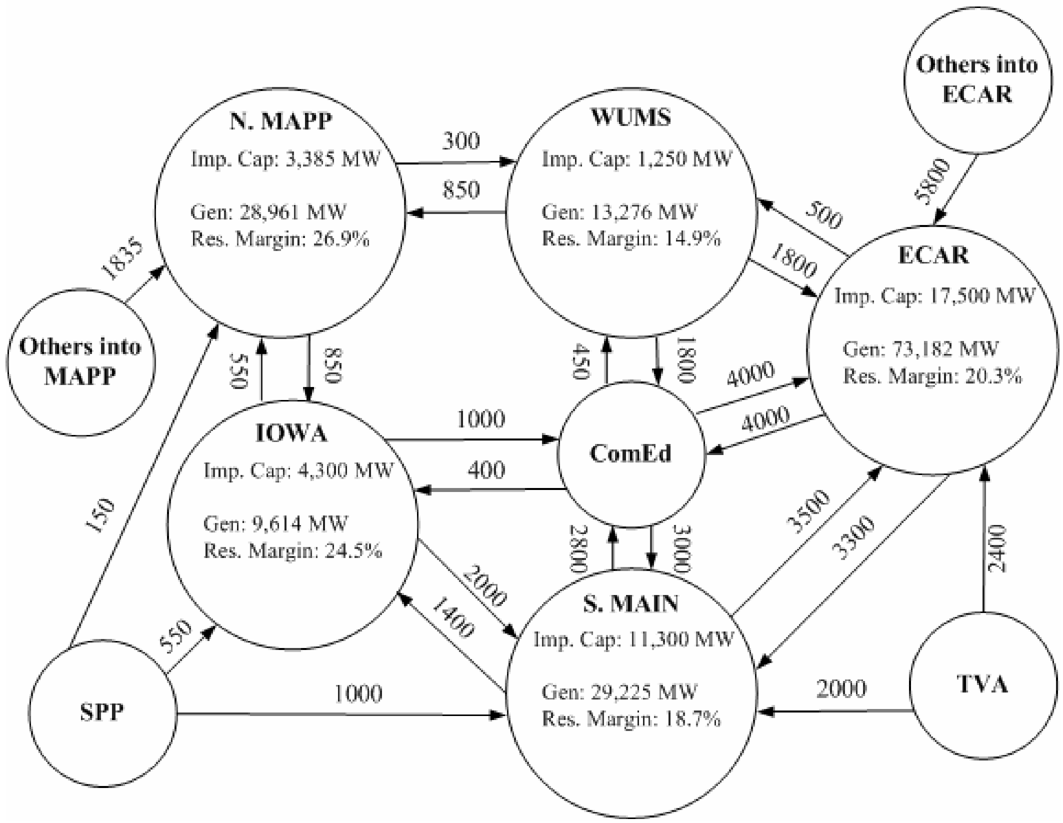


The distribution of capacity shown in Figure 1 is better viewed in light of sub-regional load and transmission interconnections. Using data from the 2002 MAIN Summer Assessment, Figure 2 shows the interconnections between Midwest ISO sub-regions and between the Midwest ISO and the surrounding areas. The diagram in Figure 2 reports the import capability, total generation, and the reserve margin for each area.[2]

The reserve margins are shown more clearly below in Figure 3, which shows the firm resources in each area as a percent of the peak load. It also shows the portion of the reserve margin that is accounted for by firm imports rather than generation within the subregion. Because the peak load data for 2002 was not available publicly or from the Midwest ISO, we calculated the reserve margins by using the 2001 peak load levels inflated by two percent to reflect load growth. In addition, firm imports into an area are credited to the area for the purposes of calculating the reserve margin.

2 The reserve margin is calculated by subtracting the peak load from the total resources in an area and dividing the result by the peak load.

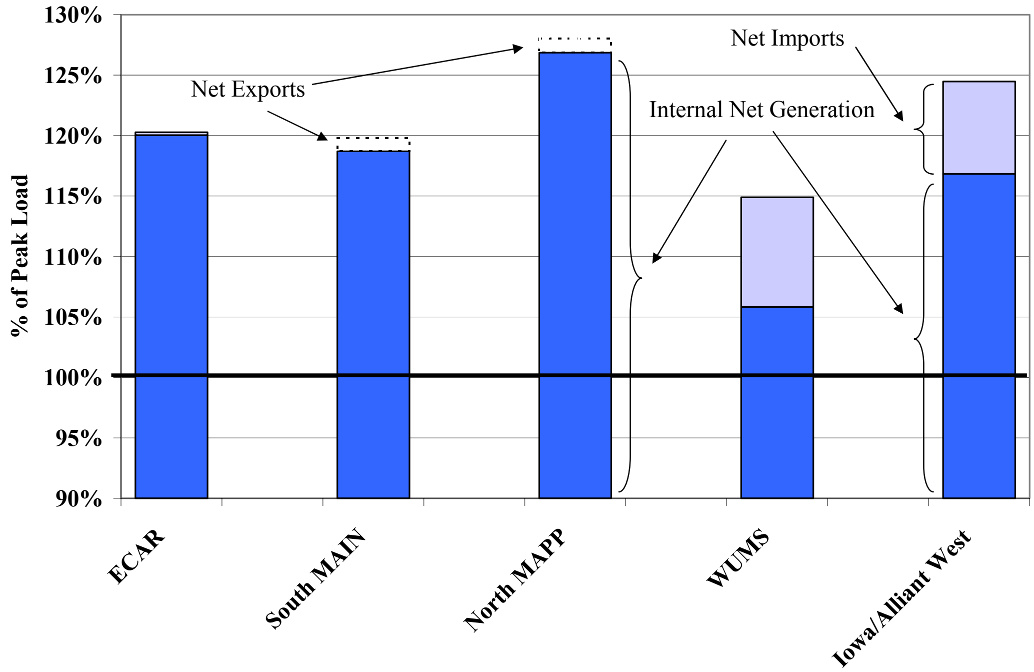
Figure 2
MISO Transmission Interconnections and Resource Balance



With the exception of WUMS, Figure 3 shows that the Midwest ISO sub-regions have access to substantial generating resources with reserve margins generally ranging from 20 percent to 30 percent. Market conditions are tighter in the WUMS area with a lower reserve margin and a heavy reliance on relatively weak transmission interfaces with adjacent areas. It is important to recognize that these estimates are calculated somewhat differently than other reserve margins.

For example, 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 reserve margin in the WUMS area is slightly lower than comparable values cited elsewhere.

Figure 3
Reserve Margins in MISO Sub-Regions



B. Capacity Profile by Fuel Used

Figure 4 and Figure 5 describe the portfolio of generation in the Midwest ISO region by fuel-type. For these figures, the Iowa sub-region was divided among the larger sub-regions with the Mid American Energy transmission area included as part of MAPP and the Alliant West transmission area included in South MAIN. The figures show that the Midwest ISO and each of its sub-regions relies heavily on coal-fired generation, which represents over 60% of the generation in the Midwest ISO region. Nuclear, oil-fired, and hydroelectric resources each represent less than 10% of the resources in the Midwest ISO region.

Natural gas-fired generating resources are 16% of the supply in the Midwest, although it accounts for the majority of the new capacity. Figure 5 also reveals that, as a proportion of total resources, MAPP has somewhat more hydroelectric generation and less natural gas generation than the other the Midwest ISO regions. Otherwise, Midwest ISO sub-regions are comparable in their generation profile.

Figure 4
Capacity by Fuel Type in MISO Sub-Regions

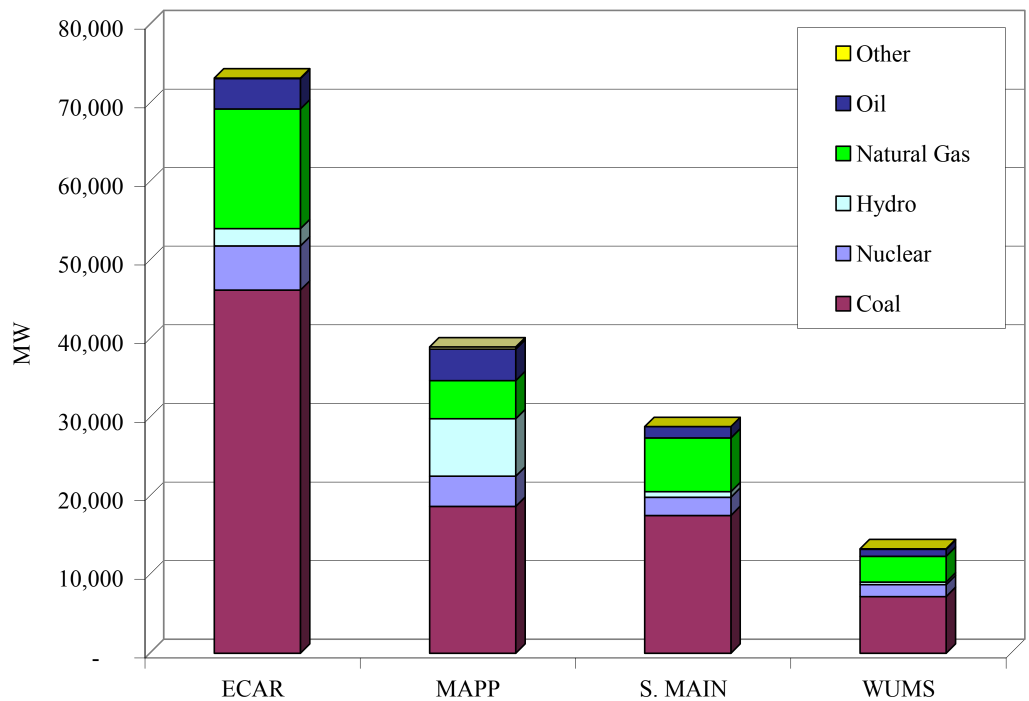
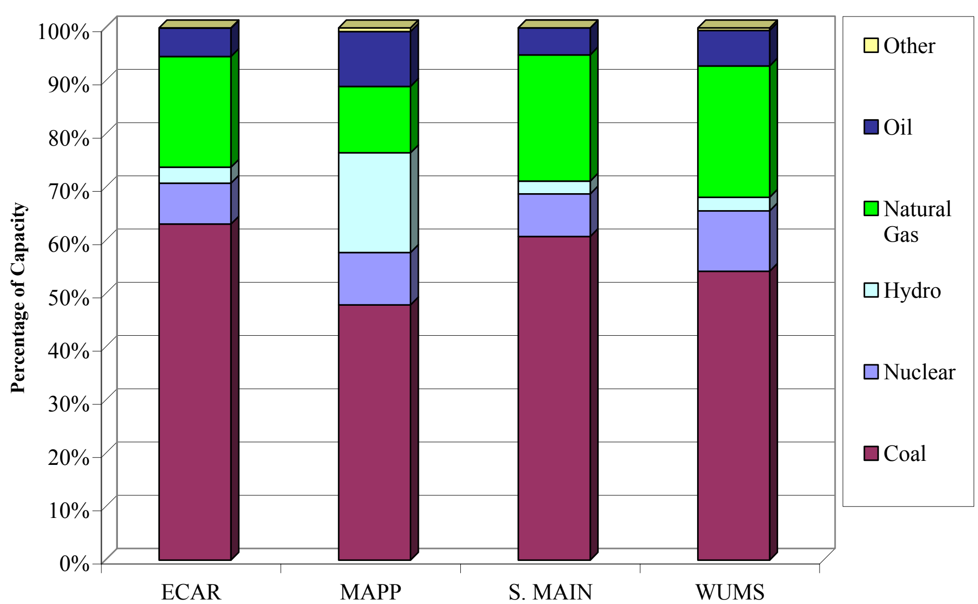


Figure 5
Capacity by Fuel Type in MISO Sub-Regions



C. Market Concentration

A final analysis of Midwest ISO generation capacity involves the concentration of ownership. We calculate the Herfindahl-Hirschman Index ("HHI") within each of the four large sub-regions. The HHI is a statistic to measure market concentration, which 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. It is primarily used to evaluate the competitive impact of mergers.

The HHI is useful in some cases when applied to 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. The sub-regions of the Midwest ISO as defined herein do not meet the criteria to be defined as geographic markets. 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. Therefore, HHI statistics should not be used to draw reliable market power inferences. Nonetheless, the market concentration within the Midwest ISO sub-regions can provide useful information and indicate areas where additional investigation or analysis is needed.

Table 1 summarizes the market concentration results, generally indicating that the sub-regions are moderately concentrated. However, it also shows that the WUMS sub-region is the most concentrated, primarily due to its limited transmission import capability.

Table 1
Market Concentration in MISO Sub-regions

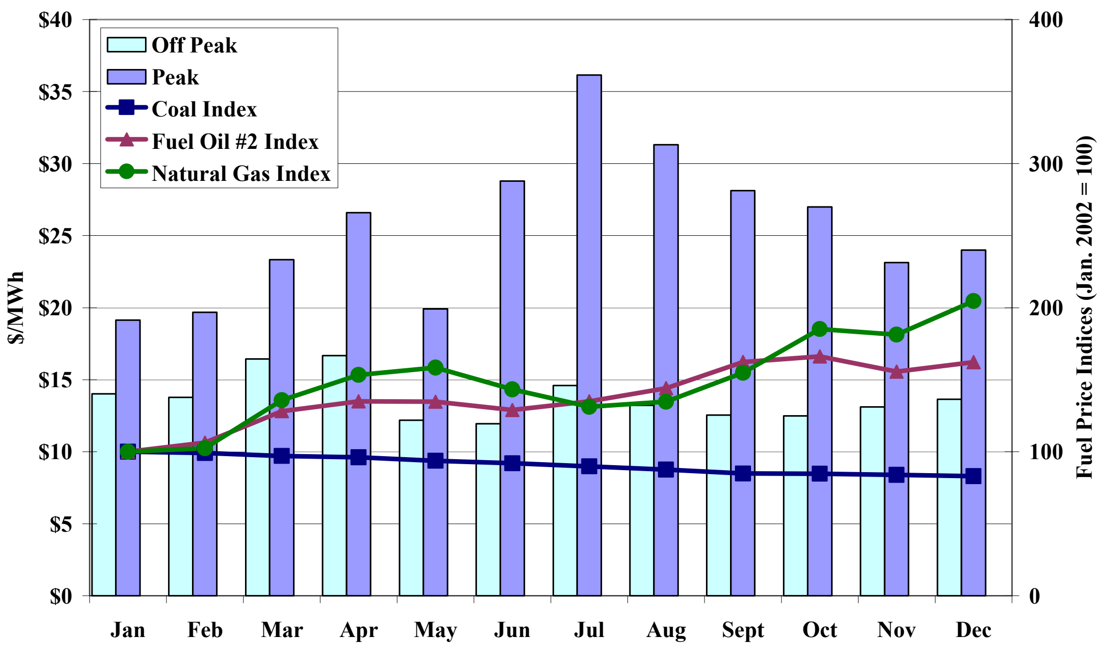
MISO Sub- Region	HHI
ECAR	1,087
MAPP	1,128
S. MAIN	1,669
WUMS	2,752
MISO-Wide	408

IV. Wholesale Market Prices in 2002

Although the Midwest ISO does not currently operate spot energy or ancillary services markets, power is traded bilaterally at the wholesale level in the Midwest. The analysis in this section evaluates the price trends in the bilateral electricity markets during 2002. In general, the prices shown are the Megawatt Daily volume weighted average prices associated with daily forward contracts initiated day ahead.

Figure 6 shows monthly average prices at the Cinergy hub during peak and off-peak periods. For reference, the corresponding Gas Daily prices are shown, along with coal and distillate prices to utilities from the Electric Power Monthly of the Energy Information Administration. The fuel indices are provided to indicate general trends in underlying input prices.

Figure 6
Monthly Average Electricity and Fuel Prices
Cinergy Day-Ahead Electricity Prices -- 2002



It is clear from Figure 6 that prices are substantially higher during peak hours due to the lack of economic storage. Likewise, prices during the summer months are higher than prices during the shoulder or winter months. The increase in gas and oil prices through the year contributed to the modest increase in peak electricity prices through the fall and into the winter. However, the decrease in coal prices moderates these effects since coal is frequently on the margin in lower load periods. Relatively high quantities of generating resources on maintenance outages in the shoulder months can cause prices to rise in these months when loads are unexpectedly high.

Figure 7 shows the daily average prices during peak hours at the Cinergy hub and the North MAIN point. The Cinergy hub is shown because it is the most liquid trading point in the Midwest. This figure includes the North MAIN pricing point because it corresponds to the WUMS area and the constraints into the WUMS area are among the most frequently binding in the Midwest. When these constraints are not binding, the prices inside and outside of WUMS should be comparable. Significant 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 than outside WUMS.

Figure 7
Daily Day-Ahead Electricity Peak Hour Prices
Cinergy and North MAIN -- 2002

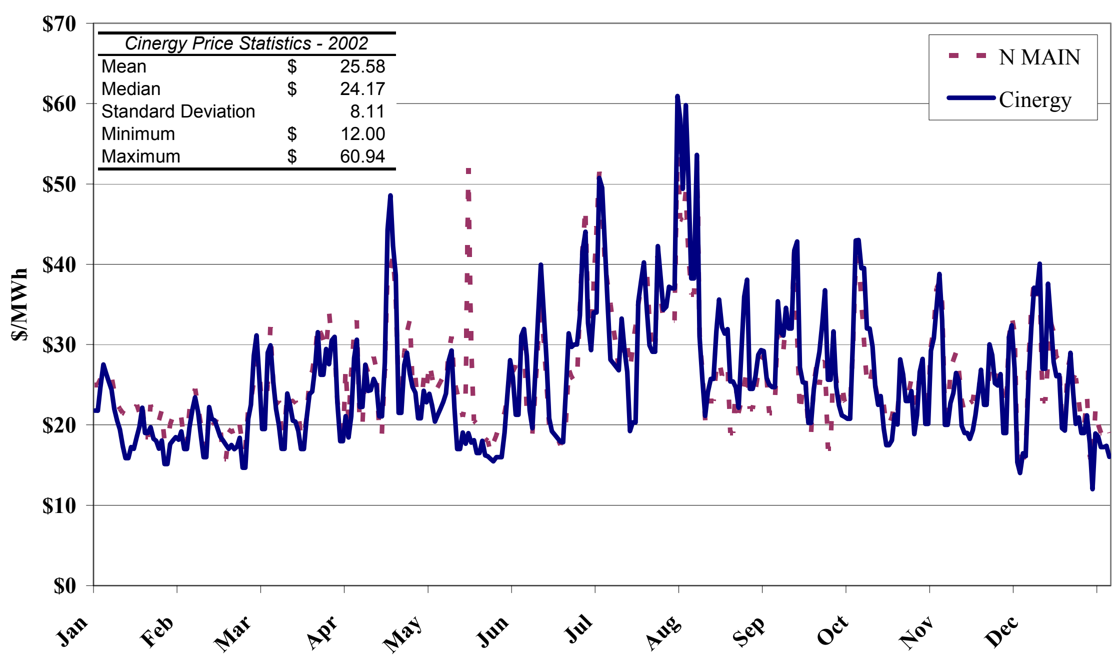
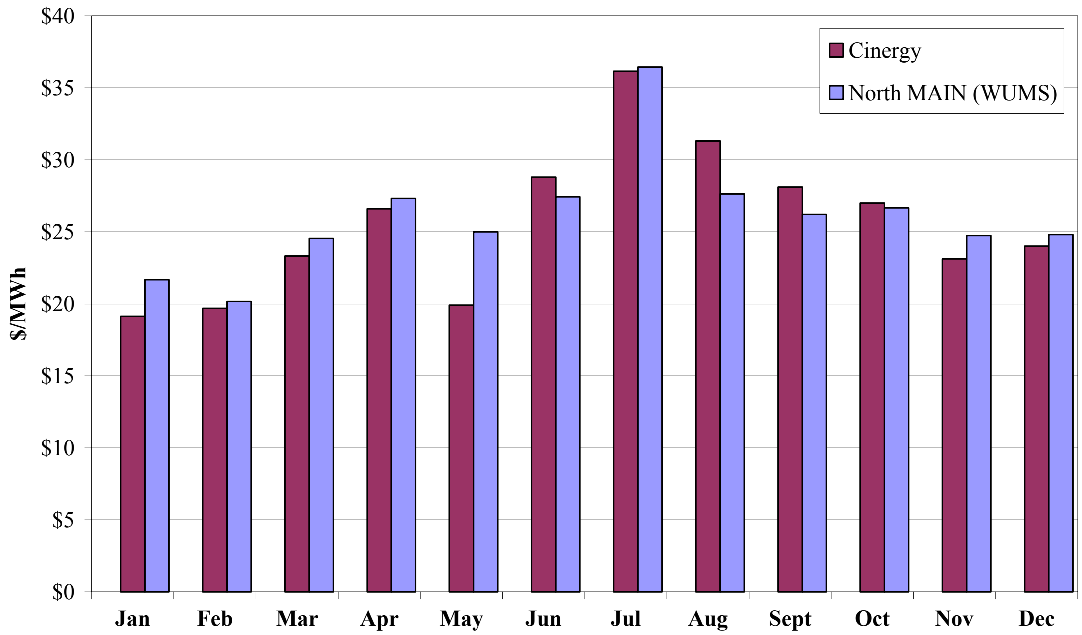


Figure 7 shows that on only one day was the price in North MAIN significantly higher than at the Cinergy hub. Despite that fact that congestion into the WUMS area can be significant, prices in the two areas are generally very similar with the North MAIN price often lower than the Cinergy price. This relationship can be better observed in Figure 8, which shows the monthly average prices at the two points during peak hours. This figure shows that the monthly average price in North MAIN was slightly higher in most months, with the exception of the period from June to October. The relationship of these bilateral energy prices and transmission constraints is analyzed in more detail below.

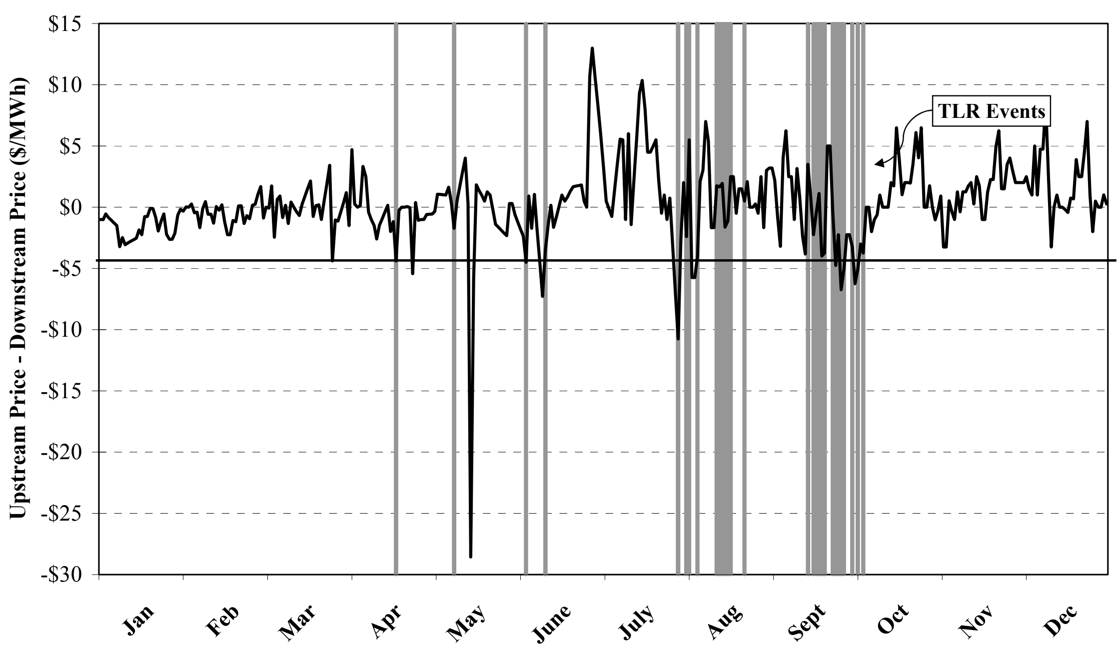
Figure 8
Day-Ahead Energy Price During Peak Hours
Cinergy and North MAIN -- 2002



The Midwest is implementing LMP spot markets that will efficiently dispatch supply to manage network constraints, setting efficient prices at each location on the network. Prices will equal the marginal system cost of serving an additional increment of demand at each location, given the supply offers and demand bids. When constraints are binding, and additional power is prevented from flowing into a constrained area, 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 markets in the Midwest. These analyses general compute the differences in prices between the upstream price and downstream price associated with a particular constraint.

One of the most frequently binding constraints is associated with the Eau Claire-Arpin flowgate that interconnects Minnesota and Wisconsin. Figure 9 shows the daily price difference between the upstream (N. MAPP) and downstream (WUMS) market locations, indicating with shading when TLR events occurred. Consistent with the discussion above, the upstream – downstream price difference should be negative when the flowgate constraint is binding. The Figure shows that some of the negative price differences coincide with the TLR events called on the flowgate. Although the figure may be useful in observing the relationship of the upstream-downstream price relationships during TLRs, econometric methods provide a more reliable means to draw general conclusions regarding these pricing relationships.

Figure 9
Relationship of Upstream-Downstream Prices During TLR Events
Eau Claire-Arpin Flowgate in 2002



This report includes two econometric tests designed to evaluate the relationship between the current bilateral prices and transmission constraints. The first analysis tests whether the mean upstream-downstream price is statistically different in days with TLR events versus all other days. The analysis is conducted on a flowgate by flowgate basis. A preliminary list of flowgates was developed based on the number of TLR events and amount of curtailed schedules during market operations in 2002. From this list, flowgates that were local in nature were removed. Local flowgates are transmission constraints that are generally managed be taking specific reliability actions in the local area rather than curtailing transactions in the broader market areas (and, hence, they had limited effects on wholesale market prices).

The analysis compares the peak prices for the day following the TLR event, which result from transactions initiated on the day with the TLR event, with prices on days without TLR events. We performed the same analysis on the prices for the day with the TLR and the results were comparable. The results are presented in the Table 2, which shows:

- The number of days in each category (i.e., with TLRs vs. without TLRs);
- The mean upstream-downstream price difference for each category; and
- the difference in these means.

Table 2
Effects of TLRs on Energy Prices

	Without TLR		With TLR		Difference	
Flowgate Name	**N**	**Mean**	**N**	**Mean**	**of Means**	**P-Value**
Eau Claire-Arpin 345 Kv	**299**	**$0.41**	**29**	**-$0.85**	**$1.27**	**0.052***
Paddock Xfmr 1 + Paddock-Rockdale	311	-$0.66	19	-$0.45	-$0.21	0.769
Albers-Paris138 For Wemp-Padock 345	317	-$0.65	13	-$0.67	$0.03	0.978
Kewaunee Xfmr+Kewaunee-N Appleton	295	-$0.72	35	$0.00	-$0.72	0.169
Lor5-Trk Riv5 161kv/Wempl-Paddock 345	**307**	**$0.81**	**23**	**-$1.56**	**$2.37**	**0.002***
Poweshiek-Reasnor 161 For Montezuma-Bondurant	300	-$0.72	7	-$1.06	$0.34	0.79
MHEX_N	319	$0.27	9	$1.45	-$1.19	0.291
MHEX_S	322	-$0.28	6	-$1.28	$0.99	0.599
MWSI	308	$0.38	20	-$0.89	$1.27	0.073

* Statistically significant at 95% level or better.

Table 2 also shows the results of the econometric test to determine whether the difference in the means in TLR hours vs. non-TLR hours is statistically different from zero. This result is in the form of a “p-value” that indicates whether the difference in the two means is statistically different from zero.[3] Economists generally employ a 95% confidence interval to determine whether a result is statistically significant, corresponding to a p-value less than 0.05. Hence, a p-value equal to or less than 0.05 indicates a statistically significant result.

The econometric results in Table 2 show that for all but two of the flowgates, the difference in the means is not statistically different from zero. Hence, no apparent relationship exists between the day-ahead bilateral market prices and transmission congestion. Contrary to these results, one would expect in a well-functioning market that price differences would be affected by congestion. The two exceptions to these results are the two flowgates shown in bold in the table, which both exhibit the expected pricing relationships: (1) A negative mean exists on TLR days (prices higher in the downstream area); and (2) A positive difference in the means (the difference in upstream and downstream prices becomes *more* negative when TLRs occur). Even for these two flowgates, however, the magnitude of these values is relatively small (e.g., the mean of the upstream-downstream price differences during TLRs are $0.85 to $1.56 per MWh).

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 upstream-downstream 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 upstream-downstream price difference should become more negative when the TLR occurs. Table 3 shows the regression results for this case by flowgate. This table shows the difference in the upstream-downstream price from the current day to the following day, but indicates that this difference is not statistically different than zero for any of the flowgates.

3 With this test, calculation of the p-value depends upon whether the variances of the two samples are equal. The p-values presented are those derived when an additional statistical test indicates the variances are equal at the 95% confidence level, and uses the unequal variance approach otherwise.

Table 3
Effects of TLRs on Energy Prices

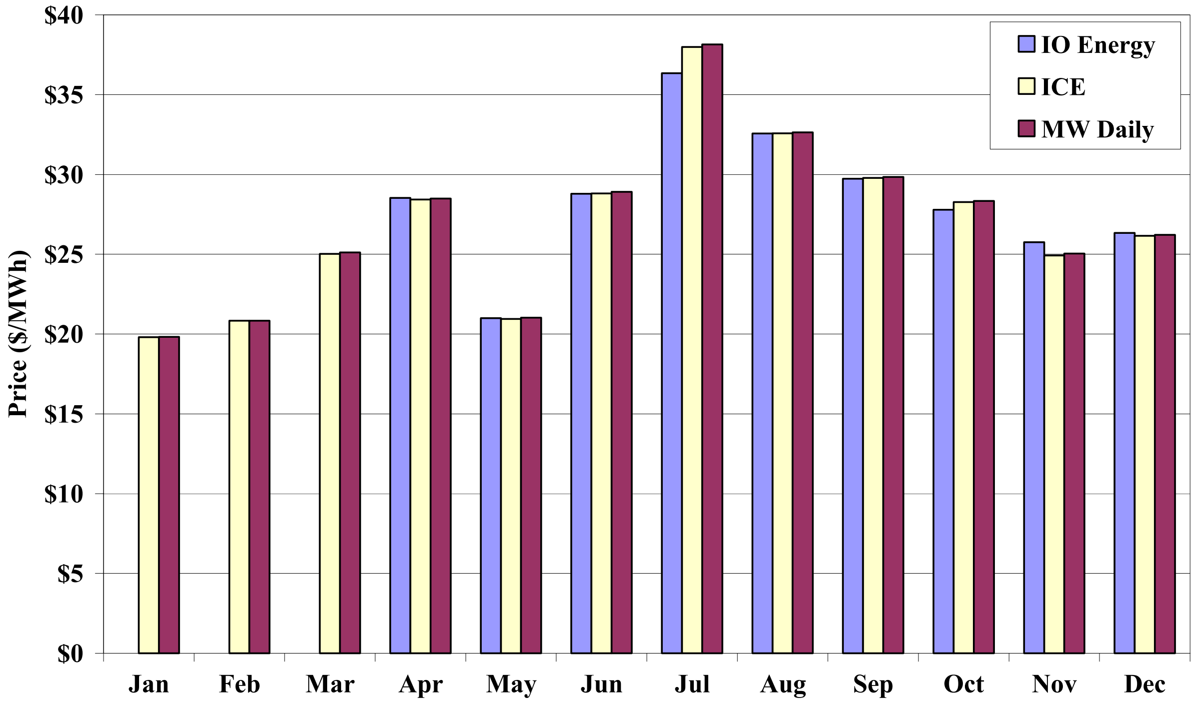
Flowgate	Est. Change ($/MWh)	P-value
Eau Claire-Arpin 345 Kv	-1.25	0.061
Paddock Xfmr 1 + Paddock-Rockdale	-0.08	0.918
Albers-Paris138 For Wemp-Padock 345	0.06	0.946
Kewaunee Xfmr+Kewaunee-N Appleton	-0.38	0.522
Lor5-Trk Riv5 161kv/Wempl-Paddock 345kv	0.47	0.584
Poweshiek-Reasnor 161 For Montezuma-Bondurant 345	-0.75	0.457
MHEX_N	-0.91	0.434
MHEX_S	0.84	0.676
MWSI	-0.15	0.835

Taken together, these results indicate that the daily bilateral prices in the Midwest do not generally reveal the presence of transmission congestion. Hence, the bilateral market prices do not provide transparent and accurate price signals for participants in the Midwest market. These conclusions must be tempered by the following factors.

First, the prices are daily prices associated with power sold one day forward. These prices are not as accurate as intraday hourly prices that would reflect congestion at the time it is actually occurring. This is primarily because transmission congestion cannot always be foreseen one day-ahead since it is sometimes caused by random or uncertain factors (e.g., transmission or generation outages, weather patterns and other load determinants). Unfortunately, intraday trading is not nearly as liquid as daily trading and reliable intraday prices are generally not available.

Second, the prices are developed through a survey process that may not be completely accurate, particularly in locations where bilateral transacting is less liquid. For example, we perform many of our market monitoring tasks using both Megawatt Daily price data and similar price data from IO Energy and the Intercontinental Exchange ("ICE"). These sources produce prices for the same locations using very similar methods. In general, the prices posted from these sources are consistent. This can be seen in Figure 10 below that shows the monthly averages of the daily peak prices from Megawatt Daily, IO Energy, and ICE.

Figure 10
Monthly Average Day-Ahead Energy Prices for Cinergy from Alternative Sources
January to December 2002



This figure shows that the monthly average of the day-ahead peak prices were generally within 1 percent of one another, although this difference was as high as 5 percent. Because Cinergy is a liquid trading point in the region, the pricing information at this point is likely more reliable than the information at more thinly traded locations.

Despite these caveats, we find that the current pricing in the Midwest is not transparent, particularly with regard to transmission congestion. The Day-2 energy markets to be implemented by the Midwest ISO 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.

V. Assessment of Transmission Utilization

During 2002 the Midwest ISO began providing transmission service and performing reliability coordination functions. In this section, we summarize and assess the Midwest ISO's transmission operations and the utilization of the system.

With regard to transmission operations, the report concludes 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.

This section includes the following analyses and findings:

- We analyze the disposition of transmission service requests and find that the volume of approved transmission service requests increased dramatically in 2002 in response to discounting of firm and non-firm transmission rates on through and out service and through improved modeling of AFC.

- We also analyze TLR events and find that the number of significant events (those events involving curtailment, holds on transmission service, or redispatch of generators) were relatively numerous, increasing in amount from the previous year on comparable facilities. We found that half of the TLR events in 2002 were related to facilities serving the relatively congested area of WUMS.

- To further evaluate the TLR events, we analyzed the real-time flows on flowgates during TLR events and found unambiguously that the Midwest ISO's TLR calls appear to be supported by the real-time operating conditions. Further analysis of real-time flows on flowgates during periods without TLR calls also shows TLRs were called in a consistent and reliable manner.

- Lastly, in this section, we review hourly AFC calculation results and the short-term transmission service request approval procedures and find that while AFC calculations do not appear to track real-time flows well, they have improved over time and continue to be subject to a number of ongoing initiatives among Midwest ISO members to improve the process. The Midwest ISO has also modified the approval process to complement the AFC calculations and to help increase the amount of transmission service that can be provided.

With regard to the utilization of the transmission system, we conclude that the implementation of the Day-2 energy markets will generate significant economic efficiencies. This conclusion is based, in part, on our analysis of the TLR process as a means to manage transmission congestion. We examine the efficiency of TLR procedures by comparing TLR results to a simulated optimal dispatch of generation to manage the same congestion.

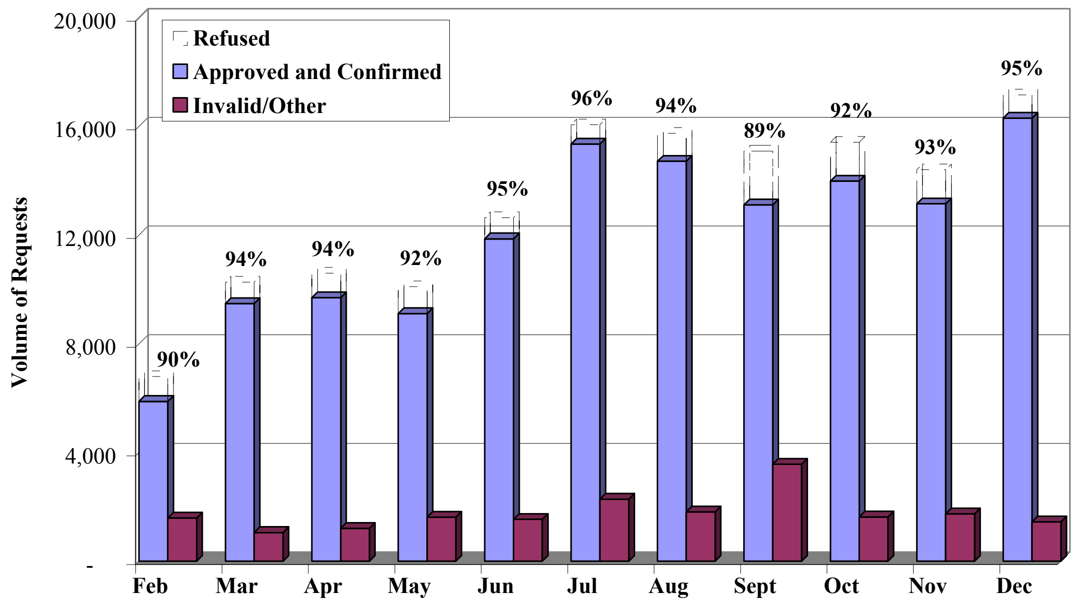
We found that the TLR process curtails roughly three times the quantity transactions as the quantity of generation that would be economically redispatched under an LMP market. On some of the most congested facilities, TLR curtailments can rise to as high as five times the quantity of economic redispatch. These results indicate that the Day-2 markets planned by the Midwest ISO promise substantial efficiency improvements for the Midwest.

A. Summary of Disposition of Transmission Requests

Figure 11 shows the disposition of requests for transmission reservations from February 2002 (when the Midwest ISO tariff began) to December 2002. The figure shows the volume of approved requests increased substantially. Approved non-firm requests increased by 173 percent and approved firm requests increased by 129 percent.

The vast majority of transmission requests ultimately fall in one of two categories: (1) approved and confirmed; or (2) refused – generally due to a lack of available transmission capability. The “other” category includes: invalid, denied, annulled, and withdrawn. These other categories ultimately do not result in a transmission reservation due to the participant’s action or the validity of the request. Some requests must be studied before a request can be approved or refused. Because this is an interim designation, the figure does not include this category.

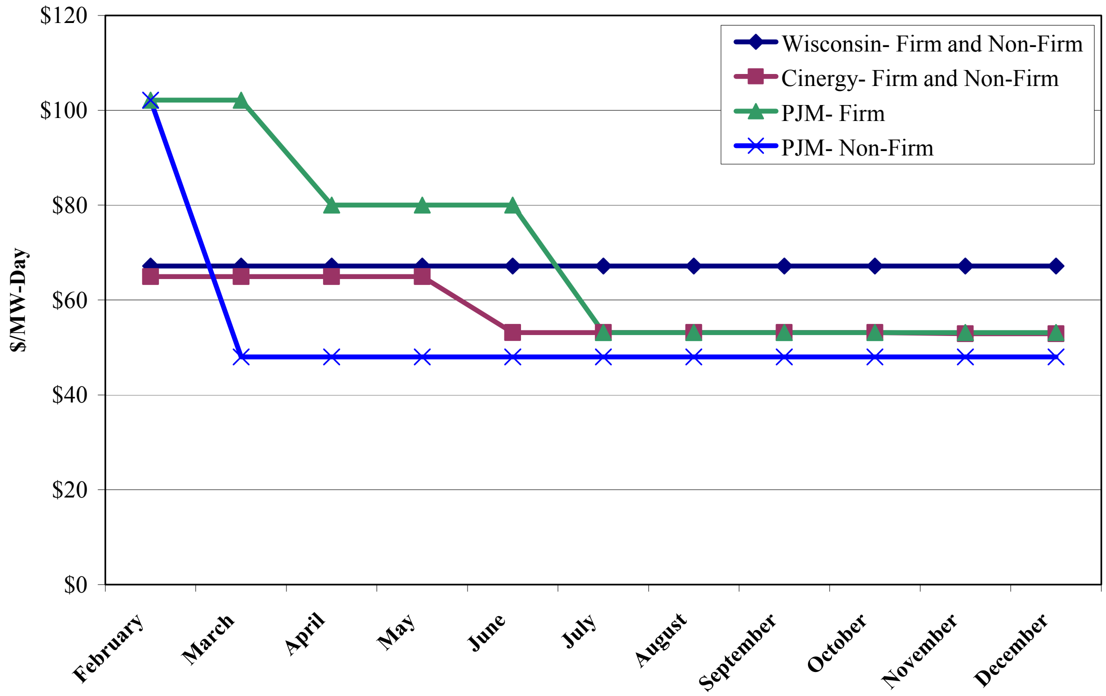
Figure 11
Disposition of Reservation Requests in 2002



In addition to the increase in approved requests, the figure shows that the Midwest ISO approved a consistently high portion of the submitted requests, ranging from 89 percent to 96 percent on a monthly basis during 2002. Most of these requests are short-term service requests, which contributes to the relatively high approval rates. The differences in approval rates for various types of service are discussed in more detail later in this section.

The "other" category remained at modest levels throughout the year, with an increased quantity shown in September 2002. This increase was caused by a data entry error rather than an increase in real requests in this category. The increase in approved reservation requests was caused primarily by two factors: (1) the increasing discounts offered by the Midwest ISO for non-firm transmission service throughout the year; and (2) improved modeling of available flowgate capability. With regard to the transmission rates, Figure 12 shows the trends in transmission rates that have contributed to the increase in reservations.

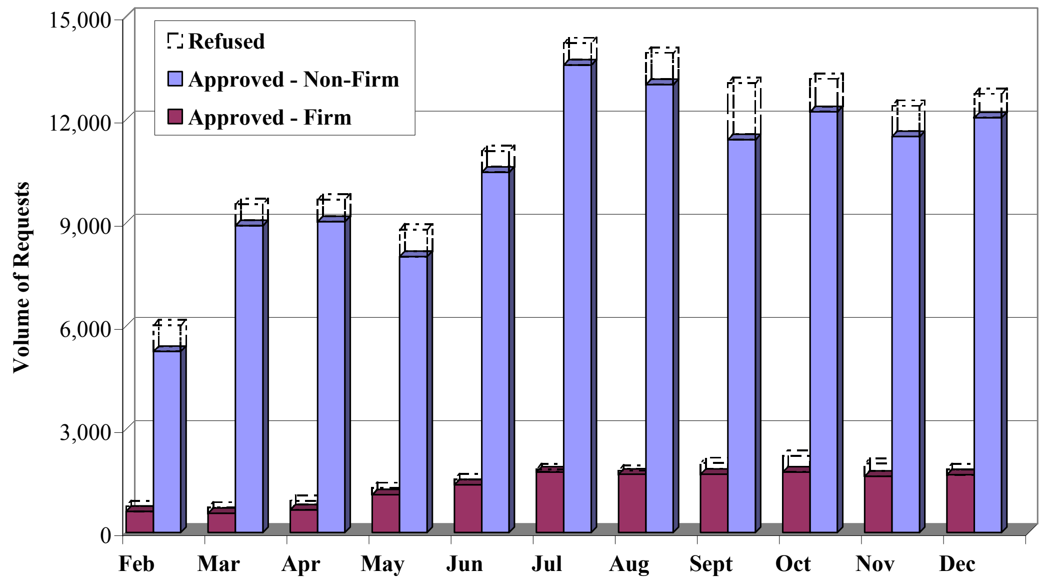
Figure 12
Summary of Transmission Rates During 2002
Daily Firm and Non-Firm Peak Service



To better understand the patterns of transmission service that occurred during 2002, it is useful to show the monthly quantities approved and refused by type of service (firm vs. non-firm) and duration of service. With regard to the type of service, Figure 13 shows the quantities of non-firm and firm transmission requests by month in 2002. This figure shows that the quantities of firm and non-firm transmission requests rose significantly over the year. In addition, the approval rates for both firm and non-firm service were consistently high throughout the year.

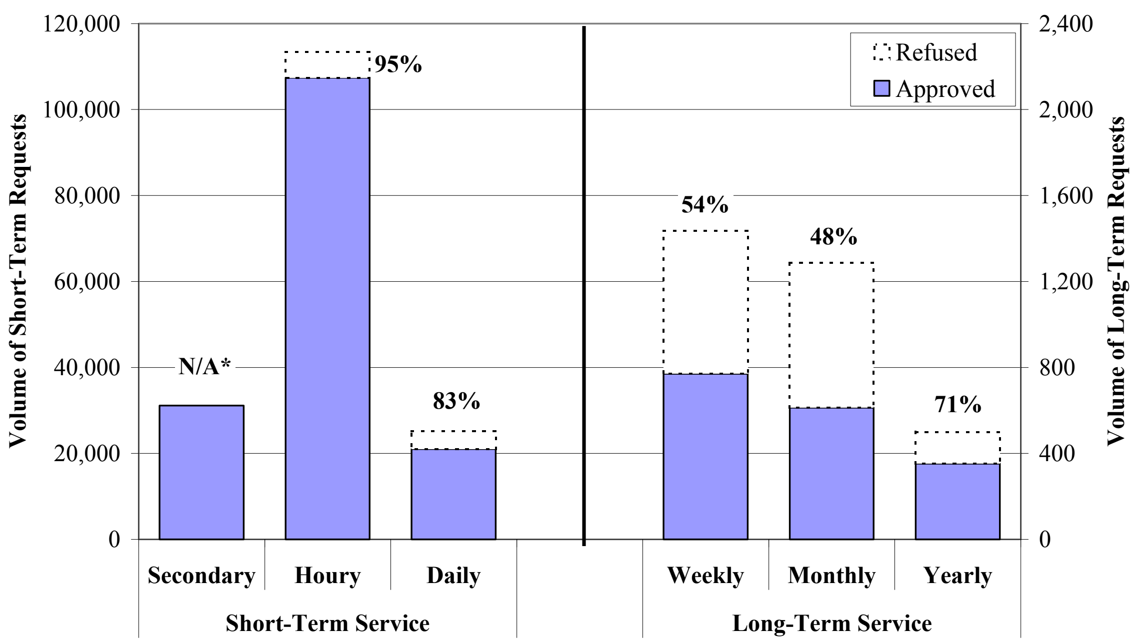
Non-firm requests increased by 141 percent from February to December. Firm requests increased by 112 percent. These percentages do not include the "other" category shown on the prior figure. Approved requests increased more sharply than the total requests because the portion of the requests approved increased for both firm and non-firm service. Approved non-firm requests increased by 173 percent. Approved firm requests increased by 129 percent.

Figure 13
Firm and Non-Firm Reservation Requests



In addition to the firm and non-firm distinction, we show the disposition of transmission service requests by the duration of service. Figure 13 shows the quantities approved and refused grouped by: short-term service (secondary non-firm, hourly, daily), and long-term service (weekly, monthly, yearly).

Figure 14
Short and Long-Term Reservation Requests



This figure shows that the long-term requests are approved at a much lower rate than the short-term requests, which is consistent with our expectations. The short-term and non-firm requests should generally exhibit a higher approval percentage because (i) there is less uncertainty regarding availability of transmission capability in the short-term, and (ii) the service is less of an 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. Alternatively, hourly non-firm service must only be deliverable in the next hour and can be curtailed if necessary.

B. TLR Events and Curtailments in 2002

The Midwest ISO manages transmission congestion through the NERC TLR Procedures.[4] Under these procedures, the Midwest ISO monitors real-time flowgates relative to their ratings limits. Under NERC Policy 9, 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 loading.

One of the actions reliability coordinators may take is to invoke a TLR procedure. A TLR of Level 3a affects transactions in the next hour. If this level is called, the lowest priority non-firm service schedules for the next hour will be limited in order to allow higher priority service to be scheduled or to decrease the flow in the next hour on the relevant flowgate. A Level 3b TLR affects transactions in the current hour. If this level is called, non-firm transmission service will be curtailed (lowest priority first) as needed to maintain system security. Under a TLR Level 4, generation will be redispatched or the transmission system will be reconfigured to provide relief for the flowgate. For example, American Transmission Company ("ATC") coordinates a redispatch process that will redispatch generation to resolve congestion within Wisconsin when a TLR Level 4 is

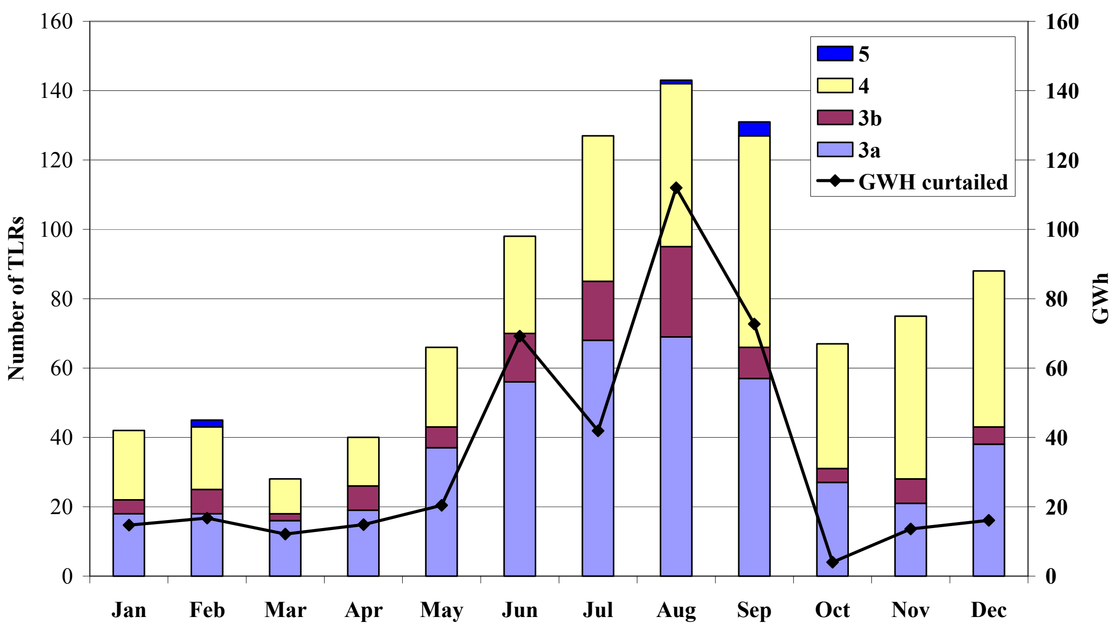
4 See NERC Policy 9 and Appendices 9C1, "Transmission Loading Relief Procedure – Eastern Interconnection"; 9C1B, "Interchange Transaction Reallocation During TLR Levels 3a and 5a"; 9C1C, "Interchange Transaction Curtailments During TLR 3b"; and the "Parallel Flow Calculation Procedure Reference Document".

invoked. Under TLR Levels 5a and 5b, firm transmission will be put on hold or curtailed. Under TLR Level 6, emergency actions will be invoked.

The Midwest ISO's primary reliability tools include a real-time flow monitoring system (flowgate monitoring tool or "FGMT") and the Interchange Distribution Calculator ("IDC"). The FGMT alerts reliability coordinators when flows are approaching their operating security limits (OSLs). The IDC allows the Midwest ISO to identify current and future transmission schedules for which 5% or more of their flow occurs on a given flowgate. In addition, when monitored flows approach the OSLs, the Midwest ISO may consult with control areas for additional information on current and expected changes in system conditions.

The Midwest ISO security coordinators invoked a significant number of TLRs in 2002. The analysis in this report focuses on TLRs, Level 3 or above, since it is at these levels where non-firm or firm transactions were curtailed or generation was redispatched to provide relief. Figure 15 summarizes the TLRs and associated curtailments called by the Midwest ISO in each month of 2002.

Figure 15
TLR Events and Transactions Curtailed in 2002



This figure shows that the curtailment quantities have increased as the number of TLR events have increased. As one would expect, the highest frequency of TLRs and curtailments occurred during the summer months when the demands on the transmission system was highest. Although the Midwest ISO performs reliability coordination for a larger area than any other coordinator, it has called the most TLRs of any area, invoking 65% of all the TLRs in the Eastern Interconnect.

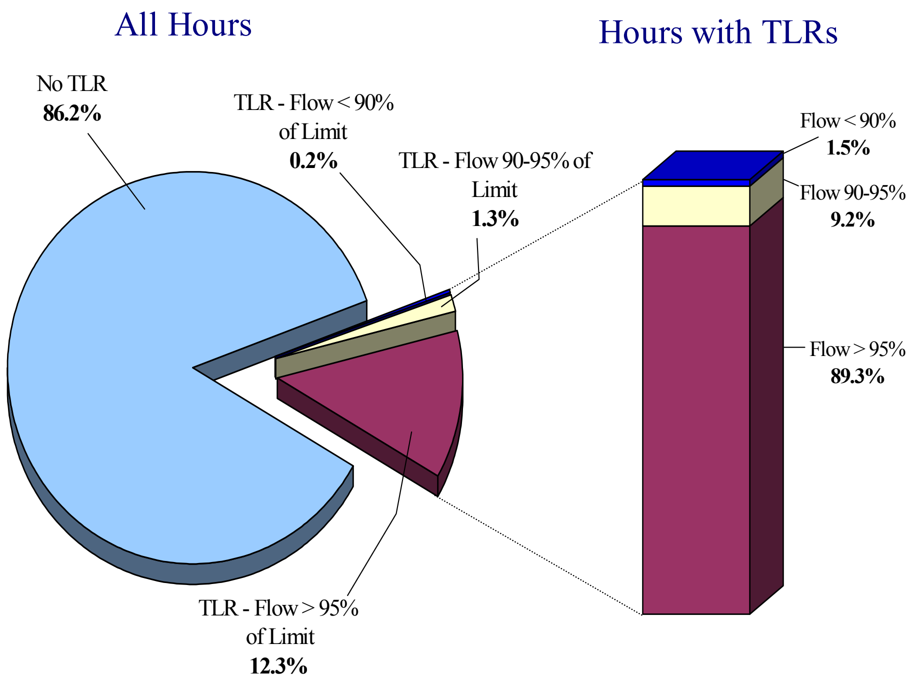
As might be expected, a significant number of the TLR events were related to flowgates in the WUMS area, most notably Eau Claire–Arpin. In fact, the WUMS area represented over 50% of the Midwest ISO's TLRs. Many of these TLRs were called on "local" flowgates in Northern Wisconsin and upper Michigan which generally can only be resolved by TLR Level 4 (redispatch) or other operating procedures (e.g. system reconfiguration). The remaining TLRs are distributed over the large number of facilities monitored by the Midwest ISO. Relative to 2001 the Midwest ISO called more TLRs on comparable facilities in 2002. The analysis in the following section evaluates the TLR calls by the Midwest ISO by assessing the system conditions under which the TLRs were invoked.

1. Comparison of TLR Events to Real-Time Flows in 2002

Because TLRs can have a substantial effect on commercial activity in the wholesale power markets, it is important to evaluate the process by which TLRs have been invoked. To make this evaluation, we examined the real-time flows on each of the flowgates in the Midwest in hours when TLRs were called during 2002. As a general rule, we assumed TLRs should only be called when the power flows approach the flowgate limits to which the operators manage the system.[5] Therefore, we evaluated the flowgate power flows during the periods when the Midwest ISO invoked a TLR, which is shown in Figure 16.

5 There are a number of factors in addition to the current real-time flows that are considered by the security coordinators (SC) when deciding to call a TLR. For example, SCs will consider next hour schedules and may call a TLR on a flowgate which has real-time flow below the reliability limit if a significant increase in flow is forecasted. Additionally, the Midwest ISO might be requested to maintain a TLR for some additional time by the control area in anticipation of an increase in required relief. Conversely, a SC may not call a TLR on a flowgate with real-time flows slightly above a limit if next hour schedules and/or generator ramping schedules are expected to bring flows within limits. In this study, we did not attempt to consider all of these

Figure 16
TLR Events and Flows on the Constrained Flowgate
July to December 2002

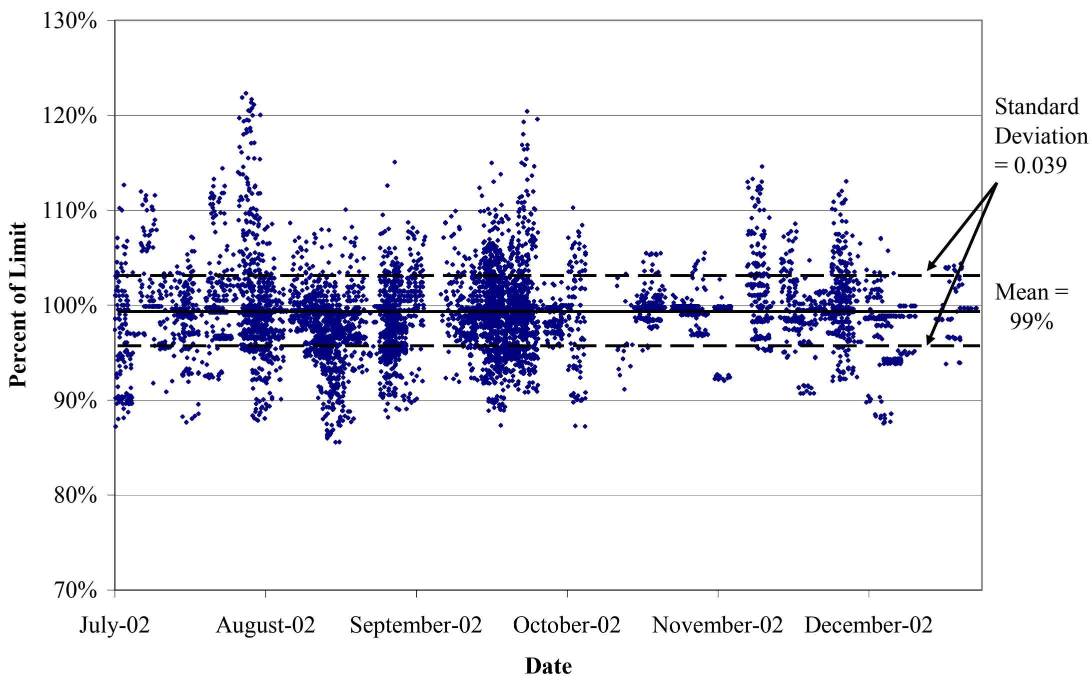


We limited our review to July to December 2002 due to data limitations on the flowgate power flows in the Midwest ISO region. Figure 16 shows that no TLRs were invoked in 86 percent of the intervals during this timeframe while the remaining 14 percent of the intervals contained one or more TLRs. The stacked bar in Figure 16 shows that in only 1.5 percent of the hours in which a TLR was called were the flows on the relevant flowgate less than 90 percent of its limit. Likewise, only 9 percent of the TLRs occurred with flows less than 95 percent of the flowgate limit.

The actual hourly flows as a percent of the flowgate limit on each of the flowgates associated with a TLR are shown in Figure 17.

factors. In addition, it should be noted that for "non-contingency" flowgates, the Midwest ISO secures facilities to 95% (rather than 100%) of the OSL. The Midwest ISO will not call a TLR if flow on a non-contingency flowgate is expected to remain below 100% (i.e., it is between 95 and 100%). If it does call a TLR, it will seek relief to the 95% level. Our analyses incorporate this understanding of TLR procedures in calculating the percentage over and under the OSL.

Figure 17
TLR Events and Flows on the Constrained Flowgate
July to December -- 2002



As shown in Figure 17, we observe that the mean flow is 99 percent of the flowgate limit during TLR events and that most of the observations are within 5 percent of the mean. As noted in the previous section, the frequency of TLRs in the Midwest ISO region is relatively high. However, from this analysis we conclude that TLRs are generally invoked only when justified based on the actual power flows over the various flowgates.

This analysis shows that a relatively small quantity of TLRs occurs when the power flow over the relevant flowgate is less than 90 percent of its limit. Nonetheless, these instances do not necessarily indicate that the TLRs were unjustified for at least two reasons. First, some of these flows relate to TLR level 4 events where a generating unit may be brought on to relieve a constraint, which can reduce the flow to less than 90 percent. Such actions can have sustained effects on the system's flows since these units may have minimum run time requirements or other operating restrictions. In these cases, the TLR will remain in effect until the generator is no longer needed or has fulfilled its minimum run time.

Second, the actual relief acquired from the TLR can be quite variable for a number of reasons. Most notably, the relief that is assumed to occur when curtailments are made based on the IDC is calculated based on control area to control area Transfer Distribution Factors (TDFs), which in some cases can result in estimated impacts that are not consistent with the actual impacts of the generators involved in the transactions. Further, TLR decisions have to be made in advance (next hour decisions occur 15-20 minutes prior to operating hour) and transactions that are curtailed have up to 21 minutes to respond.

In conclusion, we find based on this analysis that TLRs called by the Midwest ISO were consistent with real-time flows and the Midwest ISO's reliability obligations as the NERC reliability coordinator in the region. The fact that the quantity of TLRs has increased under the Midwest ISO operation is evidence that the coordination provide by the Midwest ISO has contributed to heavier use of the transmission system.

2. TLRs When Flows Exceed Flowgate Limit

In addition to evaluating the Midwest ISO decisions to invoke TLRs, we also sought to identify any cases where the Midwest ISO was slow in calling a TLR, allowing the flow to rise above the flowgate limit. To do this we identified every interval on each flowgate where the flow was greater than 100 percent of the limit and no TLR was invoked. Very few intervals satisfied these criteria.

The average frequency for all flowgates where flow was greater than 100 percent and no TLR was called was less than 0.02 percent of the intervals (approximately 1 hour) from July to December 2002. The highest frequency on any flowgate was 0.62 percent. This analysis shows that the Midwest ISO is operating the transmission system in a manner consistent with their reliability procedures.

Taken together with the prior analysis, this supports the conclusion that Midwest ISO's operators invoked TLRs in a consistent and justified manner and that Midwest ISO's TLR actions did not unduly limit wholesale transactions.

C. Analysis of TLR Efficiency

Although the previous analysis suggests the Midwest ISO has implemented TLRs justifiably, the Midwest ISO did call a significant number of TLRs. As discussed further in this section, TLR procedures are not an efficient means to manage transmission congestion. TLRs 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 TLRs 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 TLRs based on a combination of real-time information, forecasts of future-hour activity, and the inherent lags in their actions (including both the lag until the start of the next hour's schedule and the permitted lag on the ramping of curtailed transactions).

With regard to special resolution, the Midwest ISO relies primarily on the IDC to select transactions eligible for pro-rata curtailments. Transactions selected for pro rata curtailment using the IDC are selected based on TDFs, with only transactions exhibiting a TDF greater than 5 percent included. The actual impact on the flowgate of a curtailment (based on the generators involved in the curtailed transaction) can be very different than the TDFs used by the IDC models for the transactions since the TDFs are based on the source and sink control areas for the transaction.

For example, if AEP is the sink for the transaction, the generators responding to a curtailment might be in Indiana or they might be in Virginia and obviously the actual location would matter as the two generators would have very different impacts on a flowgate in Kentucky. Thus decisions based on TDFs might, in some cases, actually result in worsening congestion. Midwest ISO reliability coordinators have, in some, cases overridden IDC results when more detailed analysis showed incorrect TDFs.

One of the significant benefits to wholesale customers of the formation of the Midwest ISO is expected to be achieved when the Midwest ISO begins managing congestion through the Day-2 LMP energy markets. The analysis in this section evaluates the likely differences in the outcomes of the TLR process versus the economic dispatch process resulting from an LMP market.

To conduct this analysis, we first selected a set of flowgates that had been the source of TLR-based transaction curtailments during 2002. The purpose of the analysis is to determine the quantity of generation redispatch that would have been required to achieve the same flowgate relief as was achieved through the TLR curtailment. This analysis was conducted for every hour experiencing curtailments under a TLR Level 3 and above. We excluded TLR Level 4 events which generally did not involve curtailments, as well as events where less the 5 MWs of relief was sought. The data used for this analysis included data obtained from the Midwest ISO on transaction curtailments by flowgate and hour.

To determine the quantity of redispatch that was needed, the analysis identified the optimal incremental and decremental generation options available among generators in the Midwest ISO footprint for each hour the TLRs was in effect. This determination depends critically on the effect that increasing or decreasing generation at a location will have on the relevant flowgate. This effect is defined by a generation shift factor ("GSF"), which indicates the portion of the incremental generation that will flow over the flowgate. The GSF may be negative (i.e., the generator reduces flow on the flowgate) or positive (i.e., the generator increases flow on the flowgate).[6]

To calculate the GSFs for each of the generators in the Midwest ISO region, we received a planning load-flow case used by the Midwest ISO to calculate AFC. The case we received was based on the transmission system topology during August 2002. Based on this case, we used the PowerWorld software to calculate generation shift factors (GSFs) for each Midwest ISO generator relative to each flowgate. To determine which

[6] In the limited cases where only an incremental or decremental generator was identified, we assumed 2.5 percent GSF resources would be available to complete the redispatch. This value represents one half of the minimum 5 percent impact that transactions curtailed under the TLR would exhibit. This was generally an issue for those flowgates significantly effected by generation from other regions, such as flowgates that constitute an interface with an adjacent system.

generators could have been redispatched to manage the congestion, hourly generation levels were needed. We relied primarily on Midwest ISO unit-level data on hourly generation for 2002. As needed (when generation data was not reported for specific control areas or hours), these data were supplemented with the generation levels and the availability modeled in the AFC planning case provided by the Midwest ISO. Using this data, we conducted the following two redispatch scenarios:

- **Minimum redispatch:** most effective generating units at relieving flow on the flowgate are used (based on the generation shift factors), regardless of their cost.

- **Economic redispatch:** cost data together with the GSF information were used to choose the most economic alternative for relieving the flow on the flowgate. EIA and other public sources of data were used as available to estimate incremental energy dispatch costs, supplemented by Potomac Economics' estimates based on unit type, size, fuel type, etc.

While the minimum redispatch scenario identifies the redispatch alternative that would rely on the least amount of redispatch, the economic dispatch scenario is more representative of Day-2 market operations. Economic dispatch may require a higher quantity of redispatched MWs because generators with a smaller impact on the flowgates will be redispatched if they are a lower-cost alternative.

We calculated a statistic for this evaluation termed a "redispatch ratio". This ratio is calculated by dividing the redispatch quantity by the hourly TLR curtailment quantity. Lower ratios indicate that smaller quantities of redispatch would have been required to achieve the necessary relief on the given flowgate. For example, a redispatch ratio of 50 percent indicates that the desired flowgate relief could have been provided by redispatching a quantity of generation equal to one half of the quantity of transactions curtailed by TLR. Likewise, a redispatch ratio of 20 percent would indicate that TLRs curtailed 5 times the quantity of transactions relative to the quantity of redispatch needed to achieve the same relief. The detailed results of this analysis are presented in Table 4 at the flowgate level. The averages shown are weighted by the curtailment quantity.

Table 4
Redispatch Ratio by Flowgate for TLR Events
July to December -- 2002

				Minimum Redispatch		Economic Redispatch	
Flow Gate	TLR Events	Relief Provided (MW)	Curtailed Amount (MW)	Redispatch Amount (MW)	Redispatch Ratio	Redispatch Amount (MW)	Redispatch Ratio
Northside-Clifty Creek 138 (Flo) Trimble	6	10	161	128	80%	146	92%
Eau Claire-Arpin 345 Kv	25	51	368	107	27%	120	31%
Paddock Xfmr 1 + Paddock-Rockdale	16	27	189	59	31%	63	33%
Russel-Rockdale 138/Paddock-Rockdale	5	23	221	56	27%	58	28%
Albers-Paris138 For Wemp-Padock 345	10	16	184	158	74%	163	76%
Poweshiek-Reasnor 161kv	8	9	133	41	32%	71	56%
Lor5-Trk Riv5 161kv/Wempl-Paddock	21	21	217	48	22%	92	39%
Salem 345/138 Quad Cities-Sub 39	7	20	344	77	22%	87	24%
MWSI	17	102	477	157	30%	195	39%
N.Platte-Stvl /Gentl-Redwil	3	38	387	354	90%	354	90%
Quad City West 345kv	2	26	316	114	35%	155	48%
Sub 92-Hills Flo Sub93-Subt	1	53	630	156	25%	164	27%
Arnold - Tiffin 345kv line	2	52	447	183	38%	225	47%
Weighted Average Redispatch Ratio					**30%**		**38%**

The results show that the average redispatch ratio for all of the flowgates in the minimum redispatch scenario was 30 percent. In other words, on average, based on electrical properties alone, optimal redispatch could be expected to provide the same amount of relief with only 30 percent as many MWs redispatched as were required under TLR. Stated another way, TLR curtailments were on average over 3 times greater than an optimal redispatch to provide the same relief. At the individual flowgate level, the redispatch ratios in the minimum redispatch scenario ranged from 22 percent to 90 percent. However, the flowgates with the most TLRs (Salem 345/138 Transformer and Eau Claire-Arpin) exhibited redispatch ratios of 22 and 27 percent.

The average redispatch ratios in the economic redispatch scenario are somewhat higher, as would be expected. The average ratio in this case was 38 percent for all of the flowgates. For the individual flowgates, redispatch ratios ranged from 24 percent to 92 percent. The two most prolific sources of TLRs exhibited ratios of 31 and 39 percent.

These results confirm the assertion of many that the TLR process is not an efficient means to manage congestion because it does not seek to discriminate between more effective and efficient means of relieving a constraint versus less effective and efficient means. As a result, the TLR process typically results in curtailments that, in quantity terms, are nearly three times the quantity of generation that could be redispatched to manage the same congestion. This result indicates that the Day-2 LMP markets promise to substantially improve the efficiency with which congestion is managed.

D. AFC Issues and Analysis

The Midwest ISO calculates available flowgate capability ("AFC"), which indicates the amount of unreserved capability that exists on each flowgate that would support the sale of additional firm and non-firm transmission service of varying duration (e.g. hourly to yearly). The analytic approach for calculating AFC values is comparable to the approach used by other transmission providers to calculate available transmission capabilities ("ATC"). ATC values correspond to a contract path between two locations. Alternatively, AFC values represent the capability available on a particular transmission facility or group of 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 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. For firm service, the Midwest ISO and its members have agreed to assume all reservations in a positive direction will be scheduled (flow in the direction of prevailing or expected flow), and that no reservations in a counter-flow direction will be scheduled.[7]

In 2002, the Midwest ISO invested considerable time and effort on AFC improvements both internally and cooperatively with members through the AFC Working Group. The

7 For next hour non-firm service, the Midwest ISO generally assumes 50% counter-flows from hourly reservations that have not been scheduled.

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 have limited capability to evaluate longer-term AFC values without developing a transmission modeling system comparable to the Midwest ISO's own system. This has not been a priority due to the resources that would be required and the limited usefulness of the capability after the implementation of the Day-2 energy markets. Hence, our analysis of AFC values in this section focuses on hours when the Midwest ISO posted zero AFC for non-firm hourly PTP service.

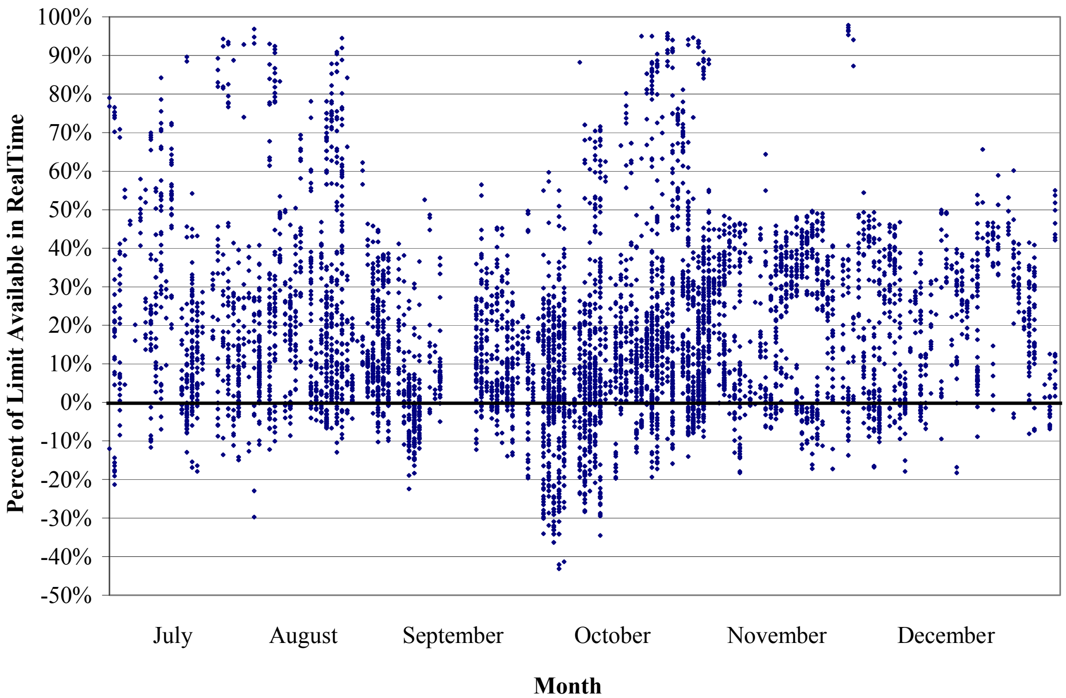
Analysis of Hourly Non-Firm AFC Values

Zero AFC postings for non-firm hourly point-to-point service should, ideally, indicate the presence of a binding transmission constraint that precludes the scheduling of additional hourly transactions. If these postings result in refused service or discourage participants from submitting requests, they will affect wholesale market activity. Of approximately 400 commercial Midwest ISO flowgates, we analyzed a sample of 32 flowgates that frequently exhibited zero AFC values during 2002.

The data for this analysis includes "coordinated" AFC values. Coordinated AFC values are AFC values calculated by transmission-owning Midwest ISO members. Over time, the Midwest ISO will assume responsibility for calculating some or all of these flowgates. Like the prior analysis of TLRs, this analysis includes only the period from July to December 2002 because the real time power flows on flowgates were not available prior to July.

To review these AFC postings, we calculated the percent of the physical capability available on the flowgate during the same time period. The physical capability is calculated by subtracting the actual physical power flow over the flowgate in real time plus the transmission reservation margin ("TRM"), if any, from the flowgate operating limit. Figure 18 shows the percentage of the flowgate limit that was physically available on flowgates during hours when the non-firm hourly AFC for the flowgate was zero.

Figure 18
Percent of Flowgate Limit Available in Real Time During Hours with Zero AFC



In general, the results suggest that the hourly non-firm AFC calculations often do not provide a reliable forecast of the actual capability that is physically available in the next hour. However, the figure indicates that the correlation of the AFC postings to the physical capability may have improved toward the end of the year. There are several factors that help explain these results. First, the Midwest ISO's hourly AFC calculations rely on accurate forecast of generation, load, and facility outages. Discrepancies between the actual load or generation and corresponding forecasted values can lead to large differences between the AFC calculations and the actual real time flows. This is particularly true for generation in close proximity to the flowgate.

In addition, the Midwest ISO "zeros-out" hourly AFC During TLRs events until the TLR level drops below 3. This explains some of the observations because, as noted previously, relief provided during TLRs may cause flows to fall well below flowgate limit for the duration of the TLR.

The effect of the understated AFC values on the market is mitigated by the fact that the Midwest ISO often approves hourly transmission service requests despite the AFC value. The tariff administrators will consult with reliability coordinators and review the physical power flows on the flowgate in reviewing requests for hourly service and will approve requests when they determine that the calculated AFC value is substantially understated.

AFC Improvements and Recommendations

The Midwest ISO has made and continues to make improvements in the process and tools used in calculating AFC values. The Midwest ISO initiated the AFC Working Group process through which it has worked with its Members and the reliability coordinators to improve the definition of the flowgates and the load flow models. We have monitored this working group to evaluate the improvements being made in estimated AFC values. Although the AFC Working Group process is ongoing, some of its 2002 activities and products include:

- Developing extensive reporting procedures to share supporting data, models, and assumptions used in calculating AFC results with the Members;
- Coordinating AFC calculations and OASIS postings with MAPP and the SPP;
- Enhancing data processing and data validation tools used by Midwest ISO staff to minimize data errors; and
- Initiating a process to track of forecasted data to actual results by Member.

The Midwest ISO has developed the 2003 AFC Improvement Plan to further improve the AFC values over the next year. The plan includes the following:

- Implementing a state-estimator (SE) model, which is a transmission model that uses metered values on voltages and flows to estimate levels of generation and load that are not metered. The Midwest ISO plans to use the SE modeling results for a 3 hour horizon to determine the system topology for the AFC model. This is expected to be implemented by Summer 2003;
- Increasing the level of modeling resolution regarding the transactions scheduled among the Midwest ISO control areas.

- Creating the ability to vary key assumptions by flowgate and time period. Such assumptions could include the counter-flow scheduling assumption or other assumptions that can be important determinants of the AFC level on a flowgate. This improvement is already underway.
- Initiating targeted reports that track deviations of forecasted data from actual data for Midwest ISO Members to identify opportunities for improvement. This is underway, but increased detail will be added over time.

Based on our review, we conclude that the AFC process has been improving and known problems are being addressed through the AFC Working Group. However, there have been persistent problems with the accuracy of data inputs upon which the AFC calculations depend. Hence, we support the implementation of the improvements listed above from the 2003 AFC Improvement Plan and recommend the following additional improvements:

- For purposes of the hourly AFC values, we recommend the Midwest ISO use the results of the state-estimator model to compensate for inaccurate forecasted generation and load information. The SE results should allow the Midwest ISO to calibrate its calculations to the actual generation and load, improving the consistency between the posted AFC values and the physical flows on the flowgates.
- The Midwest ISO should continue tracking the accuracy of AFC inputs and should continue to make AFC reports and tracking tools available to Members and the IMM. We recommend that this include coordinating with IMM staff on review of the "Score Cards" related to AFC input data.
- To the extent the Midwest ISO believes there are persistent data problems stemming from lack of full cooperation from Members, these should be brought to the attention of the IMM. We also recommend that the Midwest ISO, in consultation with the IMM, evaluate whether penalties are warranted for persistent incomplete or inaccurate data.

VI. Pivotal Supplier Analysis

In Section III we presented HHI statistics for each of the four 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 during 2002 to evaluate potential market power associated with a proposed redispatch service to relieve specific transmission constraints. It is presented in this report because it provides important information regarding the potential for local market power in the Midwest ISO region, and is a precursor to the analysis that will be necessary to define Narrow Constrained Areas ("NCAs") for purposes of the market power mitigation measures.

The Midwest ISO had planned to implement a redispatch service in 2002 to avoid firm transmission curtailments. The redispatch service was to be a market-based process through which generators would bid to increase or decrease their output to relieve the flow on congested flowgates. At FERC's request, Potomac Economics performed the pivotal supplier analysis to assess whether the redispatch service would be vulnerable to abuses of market power. The redispatch service was subsequently suspended by the Midwest ISO in order to concentrate on implementing the Day-2 spot energy markets.

A. Description of Methodology and Assumptions

This analysis sought to identify "pivotal" suppliers on the Midwest ISO system. A pivotal supplier is a supplier whose resources are required to relieve a transmission constraint to avoid firm curtailments. The analysis is performed at the flowgate level since the effects of the supply on each of the flowgates is unique. There are approximately 600 flowgates that the Midwest ISO monitors in operating the regional network. These include 500 internal to the Midwest ISO and 100 from surrounding areas.

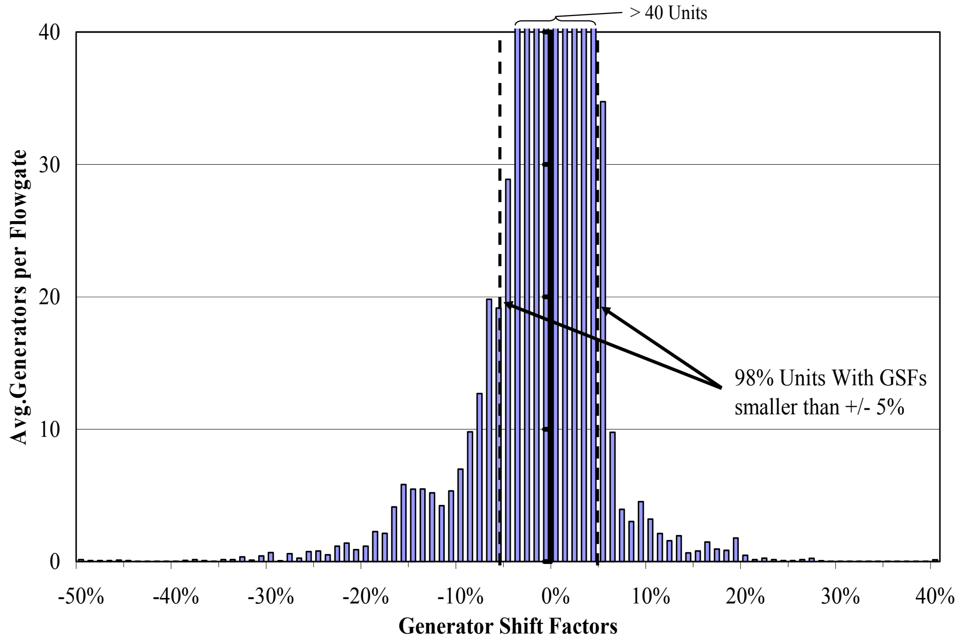
To keep the analysis manageable, we selected only a subset of these flowgates by focusing on only those that are most often congested. We selected 27 flowgates which had the highest frequency of TLR events of Level 3 and above – the level at which transaction curtailments begin.

To identify additional flowgates that may suffer congestion, we also reviewed Midwest ISO AFC results and selected those flowgates internal to the Midwest ISO showing an AFC value less than 25 percent of the flowgates' rating for July 2002. This process identified an additional 14 flowgates that were included in the analysis.

To analyze the impact that the generators in the region have on these flowgates, we estimated generation shift factors ("GSFs"). A GSF indicates what portion of a generator's output will flow over each flowgate. A positive GSF indicates that incremental production from the unit will increase the flow in the direction that the flowgate is defined (i.e., congestion on the facility would be managed by reducing the unit's output). A negative GSF indicates that incremental production from the unit will create flows in the opposite direction of the flowgates' definition, or "counter-flow", so reducing congestion on the interface would require increasing output from such a generator. Likewise, a generator with a negative GSF may create congestion on the facility by reducing its output from expected levels.

As one moves away from a given transmission facility, geographically and electrically, the GSFs decline rapidly. As a result, most generators will have only minimal impact on any given flowgate. Indeed, Figure 19 presents a histogram of the GSF factors for all of the flowgates examined in our analysis. This figure indicates that more than 98 percent of the units had GSF factors less than 0.05 and greater than -0.05.

Figure 19
Distribution of Generation Shift Factors
All Flowgates

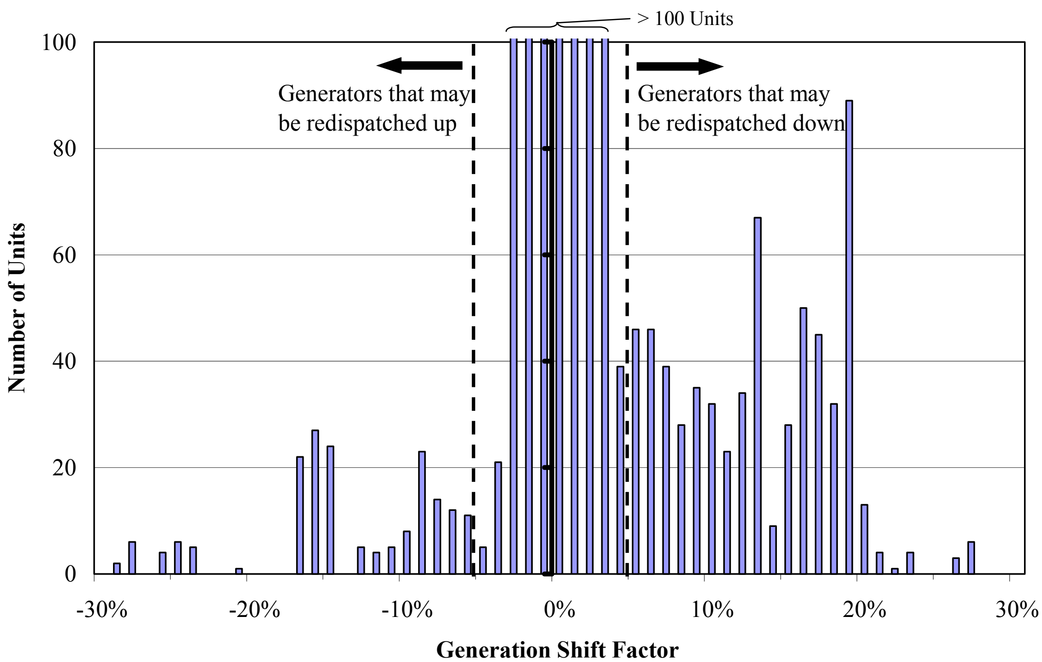


We estimated the GSF values from the results of the Midwest ISO AFC Load Flow Case for July 2002 using the PowerWorld Transmission Simulation Model.[8] The GSFs are estimated by assuming that any change in the output of one generator is replaced by changes in all other generators within the Midwest ISO. To illustrate the distribution of GSF factors that exist for a single interface, Figure 20 below shows the GSF distribution for Eau Claire-Arpin, a key transmission line interconnecting MAPP and WUMS.

Like Figure 19 the vast majority of the units in the Midwest ISO system exhibited GSFs on the Eau Claire-Arpin flowgate relatively close to zero. However, this flowgate had a much larger quantity of generating units with GSF values of greater than 5% or less than -5% compared to the averages shown in Figure 19. Because many of these generators have similar costs and are owned by a number of different suppliers, the Eau Claire-Arpin flowgate is less likely have a pivotal supplier, although not impossible under some conditions.

8 PowerWorld Simulator, Version 8.0, PowerWorld Corporation.

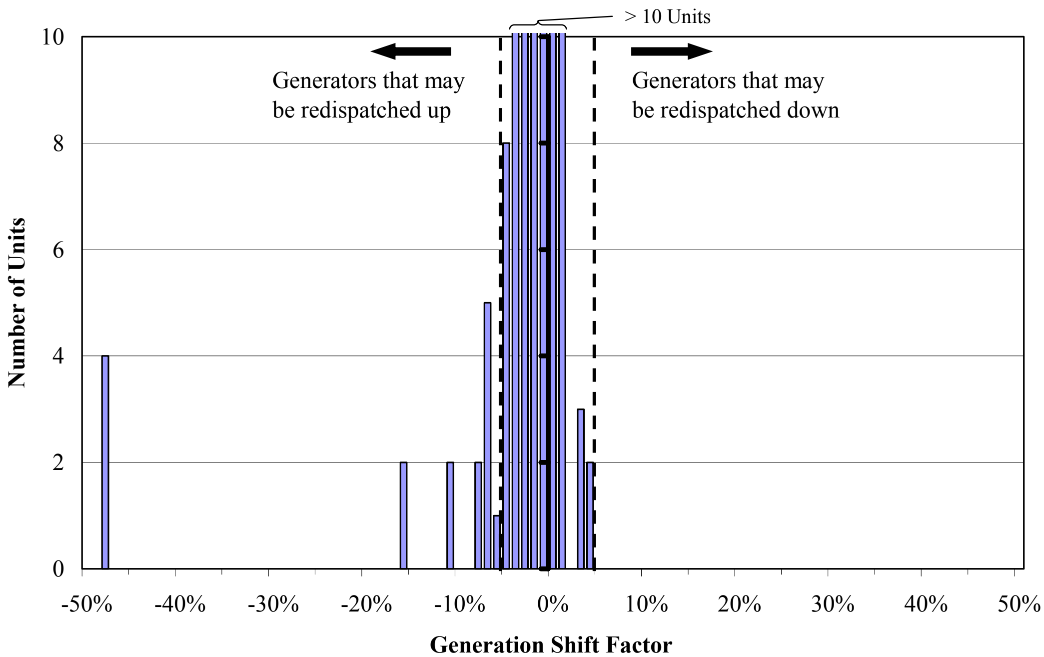
Figure 20
Distribution of Generation Shift Factors
Eau Claire-Arpin Flowgate



Source: Midwest ISO July 2002 AFC Load Flow Case, Potomac Economics Analysis.

To contrast this flowgate with a flowgate that is more likely to have a pivotal supplier, Figure 21 shows the distribution of GSF factors on the Albers-Paris138 flowgate. In contrast to the Eau Claire-Arpin flowgate, this flowgate had no units with a positive GSF of greater than 5 percent that may be re-dispatched downward to reduce the flow on the flowgate. Likewise, only 8 units could have been dispatched upward to reduce flow on the flowgate, six of which were smaller than -10 percent with the other two larger than -40 percent.

Figure 21
Distribution of Generation Shift Factors
Albers-Paris138 Flowgate



Source: Midwest ISO July 2002 AFC Load Flow Case, Potomac Economics Analysis.

Even though there are not many, the units of greatest interest are the units with the largest GSFs. Strategically operating these units will most quickly cause a transmission constraint to be binding. Alternatively, the generating units with GSF values close to zero will not have a large effect on a binding constraint, i.e., relatively large shifts in output from such units would be required to change the flow on the transmission facility in question. Because units with low (absolute) GSFs have little impact on the flowgate (or would have to change output drastically to have an impact), we eliminated units with a GSF between -0.03 and 0.03.

Incorporating units with low GSFs presents two analytic difficulties. First, low GSF units controlled by a pivotal supplier could, in theory, be used to contribute to a binding constraint that would compel the Midwest ISO to redispatch its units. However, it would by definition require the manipulation of substantial quantities of these resources to have a relatively modest effect on the flowgate. Second, units with low GSFs owned by competitors cannot be effectively redispatched to resolve the congestion created by the pivotal supplier (there is a minimum GSF value used by the Midwest ISO in its SRD process, which recognizes these practical limits).

Hence, the existence of low GSF units will not mitigate the locational market power of a pivotal supplier. Even if they were available for redispatch, the difference in shift factors would likely not mitigate the pivotal supplier's ability to obtain excessive redispatch revenue. For example, if a pivotal supplier is using a unit with a 0.2 GSF and the competing supplier owns a unit with a 0.02 GSF, the pivotal supplier may enter a redispatch bid that is 10 times higher than the competing supplier before the competing supplier's unit will be economic. To account for these issues, our analysis excluded all units with a GSF between -0.03 and 0.03.

We considered a supplier to be pivotal when it was able to cause a constraint to be binding on the Midwest ISO system that cannot be resolved by redispatching other suppliers' generation. For purposes of this analysis, all online units with GSF values less than -0.03 were assumed to be available to change output levels in response to a constraint caused by a pivotal supplier. However, because the analysis did not guarantee that supply will equal demand in total, we restricted units owned by rival suppliers with positive GSFs of less than 0.1 from reducing output to respond to the pivotal supplier. In other words, the output of generating units not owned by the pivotal supplier will not be redispatched downward unless it has a significant impact on the flowgate in question (significant in this case was defined as a 10% shift factor).

B. Results of Analysis

Two scenarios were analyzed that vary with respect to the physical capability assumed to be available on each flowgate. The first scenario uses the firm AFC value to represent the residual physical capability of the flowgate. This assumption was a worst case scenario because the non-firm uses of the flowgate would be curtailed before redispatch occurs. In addition, the firm reservations are not all likely to be completely scheduled in the same hour.

The second scenario uses the estimated non-firm AFC for each flowgate. This case modeled more available capability on each flowgate, reducing the likelihood that a supplier will be pivotal. In both cases, any negative AFC values were set to zero. These two scenarios provided a reasonable range for the amount of flowgate capability that would be unused after a typical dispatch under the Day-2 spot energy market. The results of these two scenarios are shown in Table 5. The table shows only those flowgates with one or more pivotal suppliers and shows how many pivotal suppliers were identified for each flowgate.

Table 5
Pivotal Supplier Analysis Results by Flowgate

	Firm AFC Case			Non-Firm AFC Case		
Flowgate	Pivotal Suppliers	Min Portfolio Percent	Max Portfolio Percent	Pivotal Suppliers	Min Portfolio Percent	Max Portfolio Percent
COLUMBIA_PORTAGE138CKT1_FOR_COLUMBIA_PORTAGCKT2	5	0.0%	4.1%	0		
WHITINGAVE_HOOVER_FOR_NAPPLETON_ROCKYRUN	2	0.2%	4.2%	0		
CEDAR_NATIONAL_FOR_CEDAR_TILDEN	2	0.3%	1.1%	2	0.3%	1.1%
POWESHIEK_REASNOR_161_FOR_MONTEZUMA_BONDURANT34	2	0.6%	1.1%	0		
ADAM_HAZLTON	2	1.3%	27.6%	2	1.3%	27.6%
LAKEHEAD_HIAWATHA138_UP	1	1.4%	1.4%	1	1.4%	1.4%
WHITEWATER_MUKWONAGO_FOR_COLUMBIA_SFONDDULAC	1	1.5%	1.5%	1	14.1%	14.1%
SALEM_345_138_QUAD_CITIES_SUB_39_	1	1.6%	1.6%	0		
ROCKYRUN_WHITINGAVE_FOR_ROCKYRUN_NAPPLETON345	1	1.6%	1.6%	0		
8TH_STREET_LORE161KV	3	1.7%	21.6%	1	8.2%	8.2%
CASSVL_NED_161_FOR_WEMP_PADDOCK_345	1	3.0%	3.0%	1	22.4%	22.4%
MANIPMDOLSWS	1	3.0%	3.0%	1	6.6%	6.6%
LOR5_TRK_RIV5_161KV_WEMPL_PADDOCK_345KV	2	3.7%	11.3%	1	36.4%	36.4%
OTDF_ALBERS_PARIS138_FOR_WEMP_PAD345	1	4.1%	4.1%	1	13.4%	13.4%
PADDOCK_XFMR_1_PADDOCK_ROCKDALE	2	4.5%	11.1%	2	22.6%	37.5%
FTSXFRFTSXFR	3	5.0%	10.0%	1	59.1%	59.1%
NAPPLETON345XFMR2_FOR_NAPPLETON345XFMR1	2	5.3%	17.5%	2	5.3%	17.5%
NAPPLETON345XFMR2_FOR_NAPPLETON345XFMR3	2	5.3%	17.5%	2	5.3%	17.5%
NAPPLETON345XFMR1_FOR_NAPPLETON345XFMR2	2	5.4%	17.4%	2	5.4%	17.4%
NAPPLETON345XFMR3_FOR_NAPPLETON345XFMR2	2	5.4%	17.3%	2	5.4%	17.3%
KEWAUNEE_XFMR_KEWAUNEE_N_APPLETON	2	6.3%	8.6%	2	8.8%	10.8%
RUSSEL_ROCKDALE_138_PADDOCK_ROCKDALE_345	1	10.4%	10.4%	0		
NAPPLETON_LOSTDAUPHIN_FOR_EASTKROUK_KEWAUNEE	1	12.6%	12.6%	1	16.1%	16.1%

Table 5 shows that in the firm AFC scenario, of the 41 total flowgates evaluated; 42 suppliers were pivotal on 23 flowgates. In the non-firm scenario, 25 pivotal suppliers were identified on 17 flowgates. The table also shows that maximum and minimum portfolio percentages associated with the pivotal suppliers. This was computed by dividing the quantity of resources (MW) that must be manipulated to cause the flowgate to be binding (given the AFC and the ability to redispatch rival generation) divided by the total capacity owned by the supplier. This calculation is done on an individual supplier basis, so the maximum and minimum percentages would only be different when more than one supplier is identified as pivotal.

The percentage of market capacity controlled by a supplier is important because it helps determine whether the pivotal supplier would have an incentive to manipulate the necessary quantity of capacity to cause constraints to be binding. In other words, the larger the share of a supplier's portfolio that must be manipulated to cause constraints to be binding, the lower the incentive will be to engage in that conduct. This is particularly true for withholding resources with negative GSFs if the participant has a load obligation that must be served, which would likely reduce the potential profit from the strategy.

In reviewing the results in the table above, if one were to exclude those pivotal suppliers that must manipulate more than 20 percent of their portfolio, the non-firm scenario would still include 20 pivotal suppliers on 13 flowgates. Additionally, manipulating large quantities of supplies to create congestion would more likely be detected.

We would note that the results of this analysis were conservative in identifying locational market power for two reasons. First, a supplier would only be pivotal if the constraint cannot be resolved with others' generation whose GSFs are greater than 0.3. As noted above, however, large disparities in GSF factors can allow a supplier to raise its bids substantially for redispatch even when they are not technically pivotal. For example, a non-pivotal supplier with resources that have a 0.5 GSF can raise its bids five times higher than its rivals and be accepted if their highest GSF is 0.1. This issue is not evaluated in the pivotal supplier analysis.

Second, the pivotal supplier analysis focused on unilateral market power – where a single supplier is in a position to extract excessive redispatch payments. In some cases, however, a flowgate may only be effectively managed by a combination of the resources of two suppliers. In such cases, the repeated nature of electricity markets may allow the two suppliers to coordinate their conduct to obtain inflated redispatch payments. This consideration would necessarily expand the number of flowgates that may be the source of significant locational market power.

As already noted, network constraints in some locations can create substantial market power concerns. These concerns are addressed by the proposed market power mitigation measures that have been conditionally approved by FERC. An analysis to address these issues will be conducted prior to the implementation of the Day-2 markets to define Narrow Constrained Areas for purposes of the mitigation.

C. Transmission Simulation Modeling

To confirm the conclusion of the pivotal supplier analysis we used a transmission simulation case to estimate the effects of a strategy of manipulating generating resources to cause a constraint to bind. These cases were conducted utilizing the optimal power flow option of the PowerWorld simulation model. The optimal power flow option dispatches generation and sets locational clearing prices throughout the region to minimize overall costs. To facilitate the optimal power flow, our analysis was based on the assumption that the bid prices for all generators in the region are at variable production cost levels obtained from publicly available sources.

Guided by the results of the pivotal supplier analysis, we used selected flowgates that would likely be subject to considerable locational market power due to the capability of the flowgate and the magnitude of the GSFs of the pivotal supplier's generating units. To simulate the actions of the pivotal supplier, $1000 per MWh bids were used for the units with the largest negative GSFs owned by the pivotal supplier and the output of its units with the largest positive GSF values was raised.

The difference between this simulation and the pivotal supplier analysis described above is that the optimal power flow option allows the response of rival generators to be optimal while the pivotal supplier analysis assumed that changes in the generation of rival suppliers occur at all generator buses throughout the region.

Appropriate contingency-adjusted flowgate limits were not developed because of the complexity of doing so but we relied the AFC data to enter a proxy value for the limit of the flowgate studied. Due to incompleteness of the transmission limits available for the simulation, and the dependence of the results on the specific assumed system conditions, these results were not intended to be dispositive regarding the existence of locational market power.

Nevertheless, the model confirmed that the pivotal suppliers can profitably manipulate transmission constraints. For example, we simulated $1000 bids for 900 MW of a pivotal supplier's resources with negative GSFs for the Kewaunee Transformer_Kewaunee-N. Appleton flowgate. As a result, the output from these units decreased from the base case level of 750 MW (under cost-based bids for the 900 MW) to 341 MW (with $1000 bids for the 900 MW). In other words, the constraint on this flowgate required that almost 350 MW of the pivotal suppliers' resources with negative GSFs would have to be accepted by the Midwest ISO to resolve the flowgate constraint.

VII. Development of the Day-2 Markets

The analysis in the previous sections thus far has focused on existing market characteristics and operations. Some of the inefficiencies that exist in the current wholesale markets will be addressed by the introduction of the Day-2 spot energy markets. This section of the Report briefly summarizes the market rules that have been developed and identifies those areas that are still under development.

As noted above, the Midwest ISO filed a request for a declaratory order in December asking FERC to approve the general framework of the market rules contained in the Midwest Market Initiative. FERC broadly endorsed the market rules in a February Order responding to Midwest ISO's request. The Midwest ISO continues to work on the development of these rules and mechanisms and is expected to open the markets on March 31, 2004.

A. Development of the Market Rules

The central feature of the Midwest ISO Midwest Market Initiative is the introduction of competitive spot markets for energy at each location on Midwest ISO grid. The energy market is to use a two-settlement system: day-ahead contracts and a real-time spot market for balancing. The day-ahead and real-time spot markets are not mandatory – bilateral trading will be accommodated under the rules. The LMPs will be based on the cost of meeting an increment of load at each location, including the marginal costs of congestion and losses. In the day-ahead market, participants without physical load to serve may submit "virtual" bids to buy power in the day-ahead market to sell back in the real-time market. Likewise, participants may make virtual sales in the day-ahead market.

The LMP energy markets will manage congestion on the system, providing an accurate signal of the congestion costs between locations on the grid. Currently, congestion management is based on TLRs that ignore the economic trade-offs associated with resolving transmission constraints. Financial transmission rights (FTRs) will be used to allocate the transmission revenue from the location-based congestion charges. FTRs provide an efficient method of allocating congestion charges, allow participants to hedge congestion costs, and provide a basis for market-based transmission investments.

In general, competitive ancillary services markets include operating reserves (i.e., on-line and off-line resources that can respond quickly in response to a system contingency) and regulation (i.e., resources that can respond to continuous automated dispatch signals used to follow load and maintain the frequency of the system). Competitive ancillary services markets will not be implemented initially in the Midwest. These services will be arranged by the Midwest ISO control areas until the markets are developed and implemented. The reserve obligations and related provisions will continue to be defined by the Reserve Sharing Groups, which are voluntary arrangements governing reserves in the Midwest.

The ancillary services rule development will be in phases. The current plan is to upgrade the market software shortly after introduction of the LMP markets to allow "latent" reserves to be recognized. Latent reserves are output ranges on generating units that are not fully dispatched, but that can ramp up in time to provide reserves. A second planned upgrade would introduce fully co-optimized reserve markets that will be compliant with FERC's proposed SMD.

B. Market Rules Issues

The preliminary market rules provide a solid foundation for efficient Day-2 electricity markets. However, work continues in a number of key areas, including the development of:

- Resource adequacy provisions and a safety-net bid cap as proposed in FERC's SMD notice of proposed rulemaking;
- Real-time pricing provisions to set energy prices efficiently when the market is in shortage conditions (i.e., when resources are insufficient to simultaneously meet both energy and ancillary services requirements); and

- Real-time pricing provisions to set energy prices efficiently when gas turbines, external contracts, or other resources with limited flexibility are the marginal source of supply.

With regard to the resource adequacy provisions and the safety-net bid cap, there are many ways to structure these provisions with no one correct answer. However, it is important to ensure that they do not distort the short-term operation of the system or provide inefficient long-run economic signals for investment and retirement of generation or transmission facilities.

Shortage Pricing Provisions

We made a recommendation to the Operating Reserves Task Force addressing shortage pricing issues in October 2002. This working group reviewed the recommendations and is in the process of developing market rules to address this issue. This section of the report summarizes my recommendation.

Shortages arise when energy demand and ancillary service requirements cannot be simultaneously satisfied. Although these instances generally occur in only a limited number of hours per year, prices set during these hours are an essential component of the economic signals to:

- Resources in other regions that could supply energy in response to the shortage;
- Peaking generation whose primary value is to be available under these conditions; and
- In the long term, existing and new generation needed to serve the region.

When generation capacity is adequate to meet energy and operating reserves, the Day-2 energy markets in the Midwest will establish efficient energy prices. These prices will reflect the marginal system cost of serving additional demand at each location on the network. To ensure efficient prices during shortages, however, the market rules should accurately reflect the economic relationship between reserves and energy when the supply is not adequate to meet both requirements.

When shortages occur, the energy demand will generally be satisfied while the operating reserves are compromised. Each additional megawatt of capacity supplied under these conditions, whether in the form of energy or reserves, will allow the system operator to hold an additional megawatt of operating reserves. Therefore, energy is as least as valuable as the marginal value of the operating reserves that it allows the operator to maintain.

Because energy is at least as valuable as the operating reserves, it is important to determine the economic value of the operating reserves. Under the standard market design, a market with a safety-net bid cap generally attributes an implicit value to the operating reserves equal to the bid cap. This is true for the following reasons. First, the reserve requirements are *requirements* so the LMP model and ISO operators must dispatch all available energy resources (up to the safety-net bid cap) in order to maintain the required reserves. Hence, required reserves are valued at no less than the bid cap. Second, suppliers with available energy resources with costs higher than the bid cap that cannot provide reserves (such as an external supplier) may not offer it into the LMP market. Hence, required reserves are valued at no more than safety-net bid cap.

During shortage conditions when the energy demand is satisfied only by compromising the required operating reserves, the energy prices in the reserve deficient area should be set at the bid cap. To understand why this is the case, it is important to understand from an economic perspective what is happening when the shortage conditions occur. Shortage conditions can be interpreted in one of two ways. First, the market is not clearing. Although energy demand is met, the operating reserve requirements are not satisfied. These reserve requirements are important market requirements in the sense that in non-shortage hours, the market models explicitly recognize the reserve requirements (i.e., the models are prevented from dispatching the operating reserves). When markets cannot clear, it is generally the demand that will ration the supply and set prices. The relevant demand in this case is the demand for operating reserves, which is valued at $1000 per MW as described above. To confirm the conclusion that energy is valued at this level during shortage conditions, one must determine what the market operator would have paid an incremental energy supplier to provide one MW of energy (allowing the operator to restore one MW of its operating reserves). Under the current market design, the market operator would pay up to the safety-net bid cap level for this energy.

The second interpretation of the shortage condition is that the operating reserves have become the marginal source of supply to the energy market. With limited exceptions, the operator will continue to dispatch increasing quantities of its operating reserves to meet the energy demand. If one considers the reserves as a source of energy supply, then determining the proper energy price requires that the value of the operating reserves be represented in an “offer price” for energy. For the reasons described above, the implicit value under the SMD markets is the safety-net bid cap.

When the economic relationship between the reserves and energy markets is not explicitly recognized in the market rules, spot energy prices that are determined during capacity shortages are not likely to reflect the full value of energy. Each additional megawatt of energy under these conditions will allow the system operator to hold an additional megawatt of operating reserves on another unit.

Likewise, costly actions taken by the system operator to maintain its operating reserves (e.g., curtailing load, accepting expensive imports), indicate that the operating reserves’ marginal value is greater than or equal to the costs of these actions. Failing to include these considerations in setting energy prices can cause the prices to fall inefficiently because these actions will tend to increase energy supplies available to the energy market.

In the long-run, markets that fail to send efficient signals during peak demand conditions will not retain an efficient level of generating resources, particularly peaking resources. Ultimately, this will result in a less reliable system with more frequent periods of shortages. Hence, it is important that energy prices reflect the interrelationship between energy and operating reserves.

In addition to the proposed pricing, the memo to the Operating Reserves Task Force also raised a number of settlement issues regarding payments during shortage conditions to resources that were designated to provide reserves.

The Midwest ISO staff is currently working with market participants to develop provisions that address these issues. Once reserve markets are introduced, a reserve demand curve that would be included in the market software would provide a superior means to ensure that the energy and reserve prices are set efficiently under shortage conditions.

VIII. RTO Configuration and Coordination

The Midwest ISO will be implementing markets over an extremely broad area including substantial portions of MAPP, MAIN, and ECAR. On the eastern border of the Midwest ISO will be the utilities planning to join PJM, including those systems that have joined PJM following the dissolution of the Alliance RTO. The current configuration of the Midwest ISO and PJM creates significant electrical interactions between the Midwest ISO and markets to the East controlled by PJM.

The way the systems in the Midwest have been divided between the Midwest ISO and PJM create a highly irregular seam between PJM and the Midwest ISO, including the creation of non-contiguous areas within the Midwest ISO that are part of PJM. This configuration raises two principal issues if the markets are not well-coordinated: (i) the efficiency of the locational marginal prices and associated dispatch decisions, and (ii) the increased potential for strategic gaming.

To address these coordination issues, the Midwest ISO agreed with PJM and SPP to collaboratively develop a Joint and Common Market ("JCM"). This initiative is intended to address potential economic and reliability issues related to the seams between the Midwest ISO and adjacent markets and to make it easier to transact between the markets throughout the Midwest. Accordingly, this section will critically evaluate the status and plans for the JCM.

This evaluation addresses only the coordination provisions directly affecting the efficiency of the Midwest markets. It does not address the one-stop shopping or customer interfaces being developed as part of the JCM. This evaluation will include:

- An analysis of the electrical interdependence of the two systems;
- A discussion of the economic efficiency and potential gaming issues;
- An assessment of the current state of the proposals; and
- Our recommendations for improvements to the JCM framework.

A. Analysis of the Configuration of the RTO Systems

Potomac Economics conducted an analysis of the configuration of electrical facilities last summer when the former Alliance RTO companies announced their proposed RTO elections. At that time, AEP, Commonwealth Edison, Dayton Power & Light, and Illinois Power announced their intention to join PJM. First Energy, Ameren, and NIPSCo elected to join the Midwest ISO. The analysis was performed to inform the FERC decision to approve these elections.[9] FERC approved the elections with specific requirement on the development of the JCM to address reliability and efficiency concerns.

The analysis shown below is an updated analysis of the one presented in July to reflect changes in Midwest ISO's configuration, including the dissolution of the Midwest ISO-SPP merger and the subsequent decision of Illinois Power to join the Midwest ISO.

Seams arise between RTOs because electrical networks have the inherent property that power injected at one point and withdrawn at another will flow over all interconnected lines and facilities, including adjacent RTO systems. The flow that occurs on others' facilities is generally referred to as "loop flow". Loop flows are lower over longer distance (more circuitous) paths and on lower voltage facilities – they are higher on more direct paths and higher voltage facilities.

Ideally, RTOs should be configured such that the generation in each RTO area has only minimal impacts on adjacent RTO areas. In other words, they should be configured so that loop flows do not contribute to congestion in other areas. Systems with minimal loop flow can be said to have a low degree of electrical interaction. RTOs with high degrees of electrical interaction are likely to dispatch generation inefficiently by ignoring relevant constraints on each others' systems.

The analysis of these configuration issues was focused on selected flowgates in the Midwest that have been the source of congestion in the region. This selection was made

9 This analysis was contained in a letter to James Torgerson dated July 10, 2002.

based on TLR calls associated with the flowgates or the identification of the flowgates as limiting transmission elements in recent transmission studies. These flowgates are located throughout the Midwest ISO and the Midwest utilities that intend to join PJM.

The analysis also employed GSFs for each generating resource in the region. As discussed in previous sections, a GSF indicates what portion of the flow will occur on each transmission facility. We estimated the GSF values used in this analysis using the results of the Midwest ISO AFC Load Flow Case for July 2002 and the PowerWorld Transmission Simulation Model. The GSFs are produced by assuming than any change in the output of one generator is replaced by changes in all generators within the Eastern Interconnect.

Using the flowgates and GSFs, we identified the share of generation resources that would be located within the Midwest ISO, SPP, or PJM that would impact each flowgate studied. For each flowgate, we estimate the percentage of the capability with a GSF greater than 5 percent that would be located in each RTO area.[10] These criteria are employed to focus the analysis on those generating resources that are most likely to be redispatched to manage congestion on the particular flowgate.

This analysis was performed on roughly 70 flowgates, of which less than half indicate potential market issues. This analysis is summarized in Table 6 for those flowgates that show a significant level of electrical interaction between the RTO areas.

10 These criteria are applied on an absolute value basis so that generators that can relieve a constraint by reducing their output are treated comparably to generators that can relieve a constraint by increasing their output.

Table 6
Flowgate Impacts for Generation in PJM and the MISO

Flowgate Name	RTO Area	Control Area	MISO %	PJM %	SPP %
Bay_Sh_345_Mon12_345_1	MISO	FE, DECO	96%	4%	0%
Bland_Franks_345_KV	MISO	AMRN,AECI	25%	0%	75%
Breed_Casey_345_KV	MISO	AEP,AMRN	49%	11%	40%
Mntzuma	MISO	MEC	59%	3%	39%
Paddock_Xfmr_1_Paddock_Rockdale	MISO	ALTE	59%	41%	0%
Rush_Island_St_Francois_345_KV	MISO	AMRN	77%	0%	23%
Rush_St_Francois_Blands_Franks	MISO	AMRN	78%	0%	22%
Coffn_Roxfd_Ip_For_Newtn_Mt_Vrnon	MISO	IP,AMRN	36%	4%	61%
Sidney_Xfmr_Bunsonville_XFMR	MISO	IP	76%	24%	0%
Quad_Cities_Rock_Creek_345	MISO-PJM	ALTW, CE	55%	19%	25%
Bentnhrbr-Palisades345/Twinbranch-Argenta	MISO-PJM	MECS AEP	91%	9%	0%
State Line To Wolf Lake 138	MISO-PJM	CE,NIPS	76%	24%	0%
Sugrck_345_Foster_345_1	MISO-PJM	DPL,CIN	86%	14%	0%
S Canto_Star_	MISO-PJM	AEP,FE	84%	16%	0%
Bunsonville_Eugene_Breed_Casey	MISO-PJM	IP,AEP	95%	5%	0%
Cook_345_Benton_345_1	PJM	AEP	90%	10%	0%
Dumont_765_Dumteq_999_1	PJM	AEP	79%	21%	0%
Kyger_Sporn345_For_Amos_765_345XFMR	PJM	AEP,OVEC	39%	61%	0%
Olive_345_138XFMR	PJM	AEP	84%	16%	0%
Plano-Electric Junction 345 Kv	PJM	CE	48%	52%	0%

Table 6 shows that there are a number of flowgates within the expanded Midwest ISO and PJM areas that are substantially impacted by generation in other RTOs. For example, 90% of the generation affecting the Cook 345 – Benton 345 flowgate on the AEP system would be dispatched by the Midwest ISO. Likewise, 41% of generation affecting the Paddock Transformer flowgate on the Midwest ISO system would be dispatched by PJM, while 75% of the of generation affecting the Bland – Franks 345 flowgate on the Ameren system in the Midwest ISO would be dispatched by SPP.

Overall, the analysis shows:

- PJM would dispatch between 3% and 41% of the generating resources affecting the flow on six Midwest ISO flowgates;
- SPP would dispatch between 22% and 75% of the generating resources affecting the flow on six Midwest ISO flowgates; and
- The Midwest ISO would dispatch 39% to 90% of the generating resources affecting the flow on five PJM flowgates.

- The six flowgates indicated as "MISO-PJM" are those that would represent the seams between the Midwest ISO and PJM. They generally are affected by generation in both RTOs, with Midwest ISO generation having the largest effects.

Given these results, it is evident that the current configuration results in substantial electrical interactions between the SPP, the Midwest ISO, and PJM. These interactions raise significant efficiency concerns if the LMP markets are not well-coordinated. The source of the efficiency concerns is the fact that the dispatch decisions and locational prices in one RTO area will not be efficient when the RTO is causing (or could alleviate) congestion on the adjacent RTO's system. As a result, the RTO with the binding constraint will take redispatch actions that may be substantially more costly than what the other RTO could take. These actions will be fully reflected in the first RTO's LMP prices, which will exhibit an inefficiently high level of congestion. In the extreme, it is possible that some congestion will not be manageable absent coordination between the two RTOs.

A secondary effect of this efficiency concern relates to uplift costs. One of the principles of the LMP market system is that sufficient congestion revenue will be collected by the RTO to satisfy its financial obligations to the FTR holders as long as the FTRs are physically feasible (i.e., scheduling consistent with the FTRs would not exceed any transmission limits). Because the power flows created by the generation and consumption of electricity on adjacent systems will not normally be billed for the congestion it causes, the RTO can incur a revenue shortfall – where the congestion revenue collected from the participants is less than its financial obligation to the FTR holders.

When this occurs, the shortfall is generally collected through an uplift charge to the RTO's participants. Given the high degree of electrical interaction between the RTO systems in the Midwest, the customers may be subject to considerable uplift charges if the RTO markets are not well-coordinated. The provisions being developed in the context of the JCM should allow the RTOs to effectively coordinate in managing congestion in order to avoid these inefficient costs.

In addition to the potential efficiency concerns described above, poor configuration can create gaming opportunities that would not otherwise exist within the SMD markets. In a poorly configured RTO, a generation owner in one RTO can dispatch its units to cause congestion in a neighboring RTO. Having dispatched its units to create this congestion, the supplier could then schedule transactions across the neighboring system that would apparently relieve the congestion and be compensated accordingly. These concerns arise because the prices in the first RTO will not reflect the congestion occurring on the second RTO.

Even in the absence of the uneconomic dispatch of generation to create the congestion in the neighboring RTO area, the fact that the LMPs in the two areas are fundamentally inconsistent with one another can create perverse scheduling by participants to take advantage of the inconsistence. In many cases, these schedules would have no real effect in alleviating the congestion, but could generate relatively large profits for the participants.

These concerns should not cause participants or policymakers to postpone the implementation of the LMP markets. However, they do indicate the paramount importance of effective coordination between the RTOs through the JCM. Hence, the next section evaluates the progress made through the JCM to develop process to facilitate efficient coordination of power flows in the region.

B. Evaluation and Recommendations for the Joint and Common Market

The JCM agreement between the Midwest ISO, PJM, and the SPP is the natural forum in which to develop the coordination provisions that will effectively address these issues. These coordination provisions take the form of two market interfaces: (1) a market-to-non-market interface between the RTOs, and (2) a market-to-market interface between the RTOs. The current status of these interfaces is described in a draft white paper, dated April 14, 2003, written by the RTOs participating in the JCM ("White Paper").

The market-to-non-market interface involves developing rules that allow the use of TLR procedures to coordinate the redispatch necessary in the two areas to resolve transmission constraints. These rules are currently being developed in consultation with NERC. These procedures require the market area resources to be redispatched to reduce their impact on transmission facilities in adjacent areas. These procedures address the initial time frames when one RTO area is operating an LMP market operating and the adjacent areas are not.

The market-to-market interface procedures address the longer-run when PJM and the Midwest ISO are both operating LMP markets in the Midwest. Due to the timing of implementation of the markets in the Midwest, the market-to-non-market interface is likely the first interface to be needed, and has therefore been the focus of most of the JCM work by the RTOs.

The Market-to-Non-Market Interface

The White Paper describes the market to non-market interface proposal in detail, which involves identifying flowgates in adjacent areas that are likely to be affected by the RTO LMP markets. For example, PJM flowgates that would be loaded by the Midwest ISO dispatch. These flowgates will then be monitored by the RTO and redispatch would be accommodated as necessary to relieve the flow on the flowgate.

The proposed interface includes procedures to quantify the flow on the flowgate that is associated with native and network load ("NNL") versus the amount that results from the market's economic dispatch. To do this, the economic dispatch quantities will be provided to the NERC IDC. When the non-market area flowgate becomes constrained, the operator may call a TLR. In response to the TLR, the market operator would redispatch to reduce the flow on the flowgate associated with the economic dispatch.

Based on our review of the White Paper and other JCM materials, we believe this proposal will provide a workable system to allow the use of TLRs to manage loop flows created by the RTO market in adjacent non-market areas.

The Market to Market Interface

While the White Paper provides substantial detail regarding the market to non-market interface, it includes very little detail on the market to market interface. Most of the efficiency and gaming concerns raised in this section of the report pertains to conditions when two LMP markets are operating without coordination in adjacent areas with high degrees of electrical interaction. Hence, it is the market-to-market interface that will address these concerns by providing the necessary coordination between the markets.

Because it is difficult to predict when two LMP energy markets may be operating in adjacent areas in the Midwest, although it could be as soon as March 2004,[11] we recommend that the RTOs begin developing the proposed rule changes and plans to ensure that they will have sufficient time to implement the market-to-market interface before the second LMP market begins operation. To assist in the development of the market-to-market interface, we recommend market-to-market interface provisions for the RTOs to consider as they develop the proposed rules and procedures.

First, the RTOs should adopt a real-time communications interface to exchange key constraint information. This information would include the binding transmission constraints from the prior real-time dispatch together with the shadow price for each constraint.[12] The RTOs may also need to exchange pricing information for the interface points to ensure that the physical interchange between them is efficient.

It has been shown that incorporating this information in an RTO's dispatch will result in LMPs and dispatch equivalent to a single dispatch over the broader area. This is accomplished because generation will be redispatched economically by each RTO to relieve constraints in the broader region. In other words, the Midwest ISO generation

[11] This date assumes PJM initiates an LMP market in the Commonwealth Edison control area prior to the launch of the Midwest ISO's Day-2 energy markets.

[12] These concepts are discussed in detail in the following two papers. Cadwalader, Harvey, Pope, and Hogan, "Market Coordination of Transmission Loading Relief Across Multiple Regions," (1998); and Cadwalader, Harvey, Hogan, and Pope, "Coordinating Congestion Relief Across Multiple Regions," (1999).

would be redispatched to manage a constraint within PJM if it is the lowest cost option, given the generation bids. Minimizing bid-based production costs is the same objective underlying the LMP energy markets themselves.

The principal difference between our recommendation in this report and prior work in this area is that we are not recommending that the RTOs iterate in each dispatch cycle to achieve a final solution, which would likely be much more difficult. Instead, the iteration would occur over time as each 5-minute dispatch result incorporate the updated information from the neighboring RTO in the prior 5-minute period. Because it has been shown that relatively few iterations are required to converge to a solution, iterating each 5 minutes should keep the two markets continuously close to an optimal dispatch solution.

In the formulation discussed by Cadwalader, et. al., it was indicated that adjacent RTOs would have to exchange thousands of distribution factors, reflecting the impact of each generator on the constraints in the adjacent area. This should not be necessary in the Midwest. The RTOs plan to accurately model the transmission system within the adjacent areas, which should eliminate the need for each RTO to receive distribution factors from the other RTOs. However, the RTOs will need to exchange information regarding the topology of the transmission network whenever it changes (i.e., a transmission line outage).

Second, because locational prices will be efficient, the RTOs should explore creating FTRs between markets. The coordinated dispatch will result in congestion revenue being collected when the interfaces between the RTO areas are congested. Like the congestion revenue collected internally, this revenue would be available to fund the FTRs. The FTRs would allow the participants to transact financially throughout the Midwest just as they will be able to do within the Midwest ISO when the Day-2 energy markets are implemented.

Lastly, coordination will also be required in the settlement process. The settlement provisions will need, at a minimum, to address:

- Settlement of the net interchange between the RTOs;

- Allocation of the surplus congestion revenues or shortfalls associated with congestion over the seam between the market areas; and
- Allocation of the proposed FTRs over the seam between the market (or the revenue from the auction of the FTRs).

These recommendations provide only a starting point for the detailed plan that will need to be developed by the RTOs in consultation with the market participants. Because the LMP markets promise substantial benefits to the region, delays in their implementation due to these coordination issues should be avoided if possible. Therefore, I encourage the RTOs to accelerate the development of the market to market interface to ensure that it is completed when the RTOs are ready to operate LMP markets in adjacent market areas.