Title

The potential impacts of a competitive wholesale market in the midwest: A preliminary examination of centralized dispatch

Authors

Lesieutre, Bernard C.
Bartholomew, Emily
Eto, Joseph H.
et al.

Publication Date

2004-07-01

LBNL-56503

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

The Potential Impacts of a Competitive Wholesale Market in the Midwest: A Preliminary Examination of Centralized Dispatch

B. C. Lesieutre, E. Bartholomew, J. H. Eto – LBNL
D. Hale – Energy Information Administration
Thanh Luong – Federal Energy Regulatory Commission

Energy Analysis Department
Ernest Orlando Lawrence Berkeley National Laboratory
University of California Berkeley
Berkeley, California 94720

Environmental Energy Technologies Division

July 2004

http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

This work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions and Funded by the Office of Electric Transmission and Distribution, Transmission Reliability Program of the U.S. Department of Energy under Contract No. DE-AC03-76F00098.

LBNL-56503

The Potential Impacts of a Competitive Wholesale Market in the Midwest: A Preliminary Examination of Centralized Dispatch

Prepared for the
Office of Electric Transmission and Distribution
U.S. Department of Energy

Authors:
Bernard C. Lesieutre, Emily Bartholomew, Joseph H. Eto
Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

Douglas Hale
Energy Information Administration
Washington D.C.

Thanh Luong
Federal Energy Regulatory Commission
Washington D.C.

July 2004

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions and funded by the Office of Electric Transmission and Distribution, Transmission Reliability Program of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

Acknowledgements

Distribution for his support of this research activity. This work could not have been completed without the state estimator snapshots of the MISO system and the generator production cost information we received. For these, we thank Todd Ramey and his staff at MISO, and Tom Leckey at U.S. Energy Information Administration, respectively. This report has also benefited from detailed comments received from reviewers of an early draft of this work. For these, we, again, thank Todd Ramey and his staff at MISO, and also Udi Helman, Harry Singh, and Kevin Kelly of FERC, Paul Centollela of SAIC, and Tom Overbye of the University of Illinois.

Acronyms

AEWC	Allegheny Energy - Wheatland CIN
AEWI	Allegheny Energy - Wheatland IPL
ALTE	Alliant East
ALTW	Alliant West
AMRN	Ameren
CILC	Central Illinois Light Co.
CIN	Cinergy
CWLP	City WL&P-Springfield
CONS	Consumers Energy Company
DECO	Detroit Edison Company
DEVI	Duke Energy Vermillion
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EIA	U.S. Energy Information Administration
FE	First Energy
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Right
GE-MAPS	General Electric Multi-Area Production Simulation
GRE	Great River Energy
HE	Hoosier Energy Rural Electric Coop
IP	Illinois Power
IPL	Indianapolis Power & Light Co.
ISO	Independent System Operator
LGEE	LG&E Energy
LMP	locational marginal price
LTC	load tap changing
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MDU	Montana-Dakota Utility Co
MGE	Madison Gas & Electric Company
MISO	Midwest Independent System Operator
MP	Minnesota Power Co
Mvar	megavolt-ampere reactive
MW	megawatt
MWh	megawatt hour
NIPS	Northern Indiana Public Service Co.
NSP	Northern States Power Co.
OPF	optimal power flow
OTP	Otter Tail Power Co.
POEMS	Policy Office Electricity Modeling System
RTO	Regional Transmission Organization
SCOPF	security constrained optimal power flow
SIPC	Southern Illinois Power Coop.
SIGE	Southern Indiana Gas & Electric

SMD	Standard Market Design
UPPC	Upper Peninsula Power Co.
WEC	Wisconsin Electric Power Company
WPS	Wisconsin Public Service Coop.

Abstract

In March 2005, the Midwest Independent System Operator (MISO) will begin operating the first-ever wholesale market for electricity in the central and upper Midwestern portion of the United States. Region-wide, centralized, security-constrained, bid-based dispatch will replace the current system of decentralized dispatch by individual utilities and control areas.

This report focuses on how the operation of generators may change under centralized dispatch. We analyze a stylized example of these changes by comparing a *base case* dispatch based on a "snapshot" taken from MISO's state estimator for an actual, historical dispatch (4 p.m., July 7, 2003) to a hypothetical, *centralized* dispatch that seeks to minimize the total system cost of production, using estimated cost data collected by the EIA. Based on these changes in dispatch, we calculate locational marginal prices, which in turn reveals the location of congestion within MISO's footprint, as well as the distribution of congestion revenues. We also consider two sensitivity scenarios that examine 1) the effect of changes in MISO membership (2003 vs. 2004 membership lists), and 2) different load and electrical data, based on a snapshot from a different date and time (1 p.m., Feb. 18, 2004).

Although our analysis offers important insights into how the MISO market could operate when it opens, we do not address the question of the total benefits or costs of creating a wholesale market in the Midwest.

Table of Contents

List of Figures

List of Tables

Executive Summary

In March 2005, the Midwest Independent System Operator (MISO) will begin operating the first-ever wholesale market for electricity in the central and upper Midwestern portion of the United States. Region-wide, centralized, security-constrained, bid-based dispatch will replace the current system of decentralized dispatch by individual utilities and control areas. Consumers, generators, and government are justifiably concerned about the potential consequences (both negative and positive) of such a major change in the organization and operation of the bulk power system in the Midwest. Among other things, they would like to know:

1. What will be the net impact of changes in generation dispatch on total production costs? How will these changes be distributed geographically?
2. What wholesale prices (LMPs) will result from centralized dispatch of generation in the Midwest?
3. What will these LMPs reveal about the nature and patterns of congestion in the Midwest?
4. What will be the effect of using LMPs to, in effect, put a price tag on congestion?

This report addresses these questions based on what can be known in advance of the opening of the MISO wholesale electricity market. The analysis in this report was prepared for the U.S. Department of Energy (DOE) by an interdisciplinary team drawn from DOE's Lawrence Berkeley National Laboratory, the Federal Energy Regulatory Commission (FERC), and the Energy Information Administration (EIA).

The analysis focuses on how the operation of generators may change under centralized dispatch. We analyze a stylized example of the changes by comparing a *base case* dispatch based on a "snapshot" taken from MISO's state estimator for an actual, historical dispatch (4 p.m., July 7, 2003) to a hypothetical, *centralized* dispatch that seeks to minimize the total system cost of production, using estimated cost data collected by the EIA. We also consider two sensitivity scenarios that examine 1) the effect of changes in MISO membership (2003 vs. 2004 membership lists), and 2) different load and electrical data, based on a snapshot from a different date and time (1 p.m., Feb. 18, 2004).

Although our analysis offers important insights into how the MISO market could operate when it opens, we address only questions that can be examined by considering changes in generator dispatch alone. We do not address the net benefits or costs of creating a wholesale market in the Midwest. A comprehensive assessment of net benefits would require many more snapshots of market behavior, accounting for inter-temporal constraints, over a much longer study period. It would also require an assessment of the start-up costs associated with establishing the market. And, it would have to investigate the allocation, trade, and ultimate settlement of congestion revenues associated with financial transmission rights.

Table EX-1. Summary of Core Elements of Study

Study Element	Description	Comments
Objective	Compare an actual dispatch to a hypothetical, bid-based centralized dispatch for a single historical base-case: 1600 (4 p.m.) on July 7, 2003	Sensitivity analysis considers alternate loads and generation based on historical dispatch at 1319 (1:19 p.m.) on February 18, 2004.
Tool	AC Optimal Power-Flow (PowerWorld)	Addresses loop flows and voltage/reactive power issues that cannot be captured by transport or DC power-flow tools. Enforces all transmission line limits in MISO footprint.
System Model	State estimator snapshot provided by MISO	Includes a significant portion of Eastern Interconnection (~30,000 nodes, total, of which ~9,000 are within MISO footprint).
Generator “Bids”	Generator production costs provided by EIA	Generation fixed for 2% of load for which cost data were not available.
Key Study Conventions	Generation external to MISO is fixed	Sensitivity analysis considers different membership for MISO (2003 vs. 2004).
	Unit-commitment is fixed	This is a proxy for representing security-constrained dispatched in that all units committed in this historical dispatch are available for (re-)dispatch in the hypothetical centralized cases.
	Voltage limits not enforced through re-dispatch	Transformer load-tap changes are used to enforce voltage set points. Generator reactive power limits enforced.
Quantities Analyzed	Generator dispatch, line flows, system variable production cost, LMPs, congestion revenues aggregated by control area	Major congested paths are identified within control areas.

A summary of the core elements of our study is shown in Table EX-1. Both the historical and hypothetical cases share the same defining data:

- Load,
- Generator availability (commitment) and production characteristics (heat rate and fuel cost),
- Grid configuration and constraints, and
- Net imports from outside MISO.

This study uses the PowerWorld © Optimal Power Flow (OPF) tool to calculate the costs of production resulting from centralized dispatch and the LMPs and congestion revenues that result from this dispatch. The tool models the electricity grid using an AC power-flow calculation.

The core assumption underlying the use of this tool is that the market is competitive and that production cost information reported by generators to EIA can be used as a proxy for the bids these generators will offer under centralized dispatch. If the market is not competitive and generators are able to bid above their production costs and set the market clearing price, then our results will tend to over-state the benefits of centralized dispatch.

Using the MISO state estimator model and data, EIA cost data, and the OPF tool we compute the following quantities:

- Generator dispatch,
- Line flows,
- Total system variable operating cost,
- Locational marginal prices (separated into energy, losses and congestion components), and
- Congestion revenues.

We now summarize our findings for each of the four questions posed earlier:

1. *What will be the net impact of changes in generation dispatch on total production costs? How will these changes be distributed geographically?*

Our results show that the operation of a centrally-dispatched, competitive-market could lead to significant changes in operating conditions. Table EX-2 summarizes change in dispatch by generation fuel type. Generation by coal plants and to a lesser extent hydro and nuclear plants increase significantly, while generation by gas and other units decrease. These changes are not uniform; some coal plants decrease their output and some gas and other plants increase their output.

The geographic distribution of these changes in generation can be seen in Figure EX-1. The circles represent existing NERC control areas that are expected to participate in the MISO market. The black lines represent one or more power lines between MISO control areas. The green lines represent electrical connections between MISO control areas and control areas outside of the MISO system. Figure EX-1 shows absolute changes in generation by control area: from a roughly 1,000-megawatt (MW) increase (in the Detroit Edison Company area) to a more than 1,800 MW decrease (in the First Energy area). The change in generation was concentrated in the eastern part of the MISO geographical area.

Table EX-2. Generation Plant Output Changes from July 7, 2003 Base Case to Centralized Dispatch Case, by Plant Type[1]

	Change in generation (MWh)	% plants with Decreased generation	% plants with No Change	% plants with Increased Generation
Coal Plants	5,403	11%	9%	80%
Gas Plants	-3,520	69%	22%	9%
Hydro/ Nuclear Plants	705	0%	17%	83%
Other Plants[2]	-2,504	44%	22%	34%

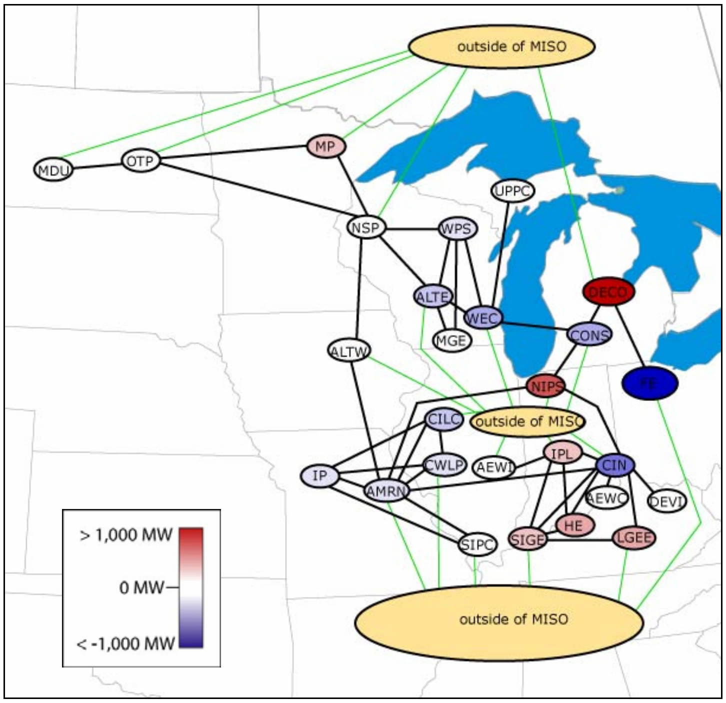


Figure EX-1. Absolute Change in Control-Area Generation between the July 7, 2003 Base Case and Centralized Dispatch

The difference in operating costs between the dispatch in the base case and the hypothetical centralized-dispatch provides an estimate of the production-cost savings that centralization might provide. In this regard, we find a significant reduction (23%) in production costs under centralized dispatch. The total variable cost of production in actual dispatch case was $1.4 M/h.[3] These costs decrease by $0.3 M/h in the centralized dispatch case.

[1] We assume the full rated capacity is available for dispatch to serve load, however, actual capacity may be limited for operational reasons.
[2] Includes petroleum, wood, and pumped storage.
[3] This is the total cost of production for the generators for which we had cost data (which cover approximately 91 percent of MISO area load).

The sensitivity analyses yielded similar values for variable operating cost reduction: 24% reduction for the case that examine alternate MISO membership, and an 18% reduction for the February 18, 2004 case. The change in generation was less consistent in the sensitivity cases.

2. What wholesale prices (LMPs) will result from centralized dispatch of generation in the Midwest?

Our analysis calculated LMPs at every bus within MISO. The average, non-load-weighted LMP of the entire system was $26/MWh. The average LMP of most individual control areas ranged from roughly $14/MWh to $38/MWh, with one area significantly outside this range at $59/MWh. The geographic distribution of these average prices is shown schematically by control area in Figure EX-2. The values in the map range from an average LMP of $10/MWh to $40/MWh, with darker colors indicating a higher average. The Northern Indiana Public Service Co. (NIPS) control area is an exception, with an average LMP of $59. It is represented in the figure as the large red circle to signify that its LMP lies outside of the otherwise well-distributed range. This exceptional LMP for the NIPS control area is largely due to several buses with high LMPs near a congested line connecting MISO and a control area outside MISO[4].

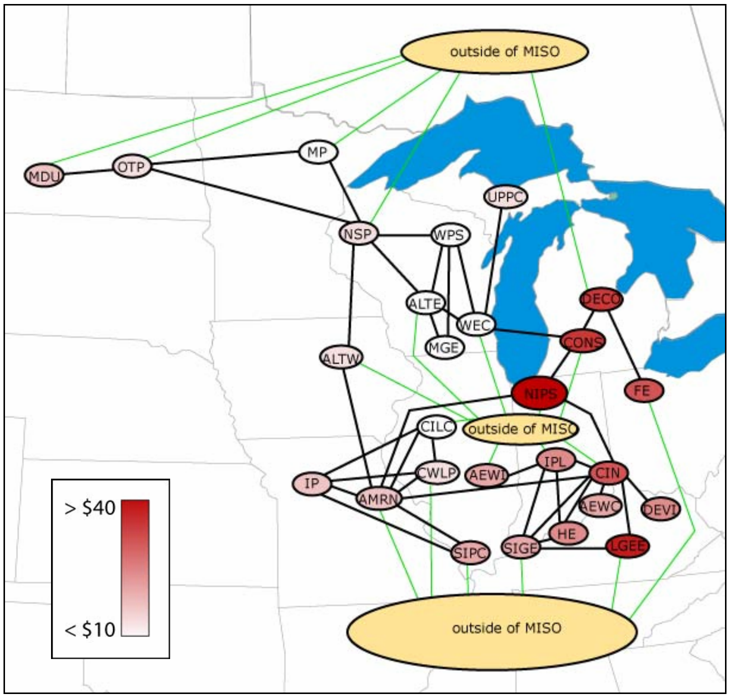


Figure EX-2. Average Control-Area LMPs within the MISO System

The sensitivity to MISO membership shows a large effect on LMPs. Figure EX-3 shows a general increase in LMPs with a notable increase in the Wisconsin and Upper Peninsula area. The sensitivity study to the February 2004 case shows results consistent with a less loaded and less congested system: the LMP distribution is almost flat. This is in contrast to the July

[4] This LMP is likely sensitive to assumptions about trade between the MISO and outside the MISO, and related seams issues.

distribution, both shown in Figure EX-4, in which the congestion is evident by the more widely distributed LMPs.

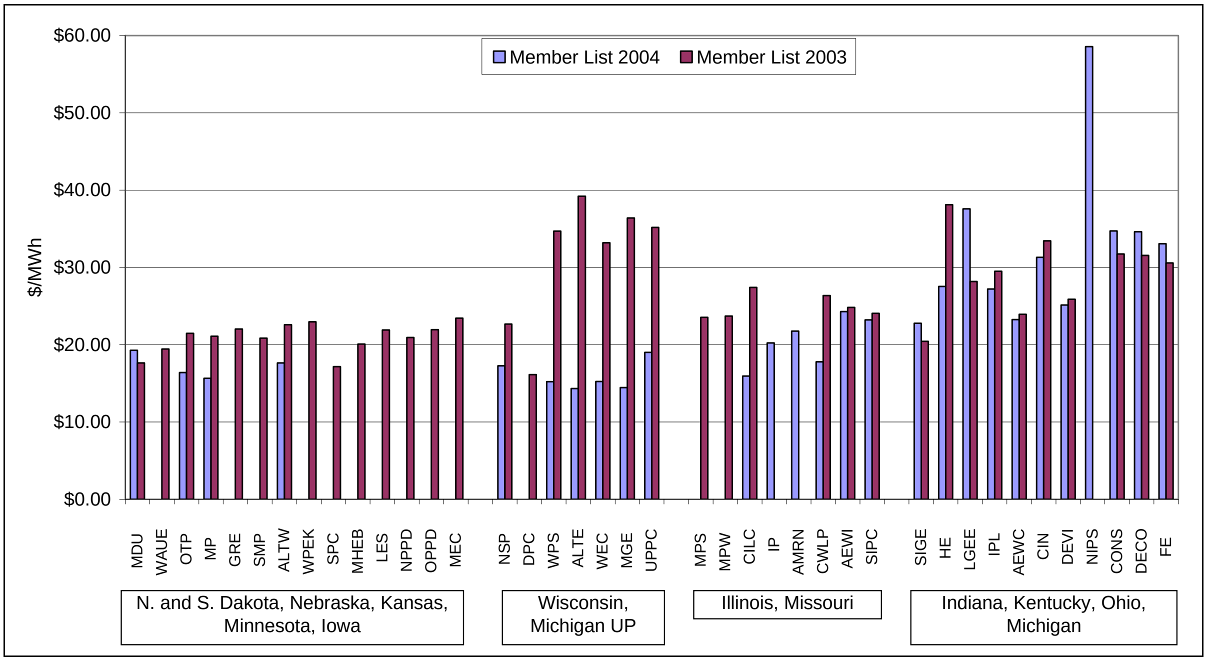


Figure EX-3. Comparison of LMPs from Centralized Dispatch, 2003 vs. 2004 MISO Members

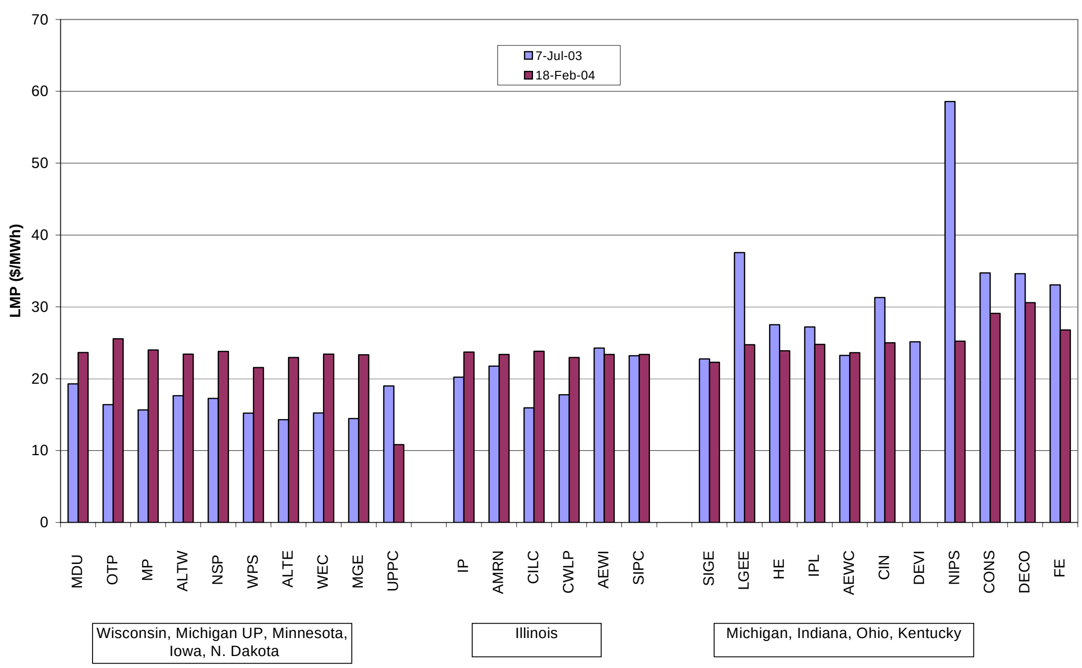


Figure EX-4. Comparison of LMPs for July 7, 2003 OPF Case and February 18, 2004 OPF Case

3. What these LMPs reveal about the nature and patterns of congestion in the Midwest?

Differences among LMPs can indicate transmission congestion in a centrally-dispatched system, otherwise flow would increase from lower price regions to higher priced regions until the prices equalize.[5] Thus, congestion occurs naturally when optimal use is made of transmission facilities that have limited capacity.

The geographical distribution of LMPs in our July 7, 2003 case and the sensitivity cases, as well as the location of the congested transmission lines listed in Table EX-2, indicate congestion in the eastern portion of the network and in the Wisconsin area. It is worth noting that in the eastern portion of the network, the congested lines are at relatively low voltages, and yet result in considerable price variation. The congested higher voltage lines in the Alliant East (ALTE) control area do not appear to have a large effect in the July 7, 2003 case. Congestion in this region is significantly more pronounced in the MISO membership sensitivity scenario.

Table EX-2. Fully-loaded Lines in the Optimized MISO System, July 7, 2003 Case

Max Nominal kV of Line	# Fully-loaded Lines	Location (Number of lines)
345	2	Alliant East (ALTE)(2)
138	4	Cinergy (CIN), Consumers Energy (CONS), LG&E Energy (LGEE), Commonwealth Edison-Northern Indian Public Service (CE-NIPS)
69	3	Ameren (AMRN) (2), Cinergy (CIN)

4. What will be the effect of using LMPs to, in effect, put a price tag on congestion?

Congestion revenues result due to the difference in value (price) for energy at the sending and receiving ends of a transmission line. The product of the flow times this difference in price represents a premium paid due to congestion. This premium may be low if the prices are nearly equal on both ends of the line, or may be large if the prices diverge. Thus, congestion revenues (these premiums) are natural measure of the impacts of congestion. Also important, when summed over the whole system, congestion revenues represent the increased payments by loads in excess of receipts by generators (not accounting for disbursements based on financial transmission rights).

Net congestion revenue in the optimized MISO system for the July 7, 2003 case was nearly \$230,000/h. The majority of this congestion revenue was within the boundaries of existing NERC control areas in the MISO footprint. Only 0.6 percent of total congestion revenue (about \$1,500/h) is at the seams between existing control areas in the MISO footprint. This is an interesting finding because it might be presumed that the introduction of centralized dispatch

[5] Differences will still exist do to losses.

would result in greater congestion along the borders separating control areas. Our analysis indicates that this is not the case.

Figure EX-5 shows the geographic location of both intra-area and inter-area congestion. All intra-area congestion ranges from $15,000/h to -$15,000/h with the exception of Cinergy (CIN) and LG&E Energy (LGEE), which have nearly $48,000/h and slightly more than $150,000/h of congestion revenue, respectively. These areas are shown as slightly larger than the other control areas to indicate this difference. Congestion between control areas ranges from nearly $6,000 to around -$3,000/h on each line.

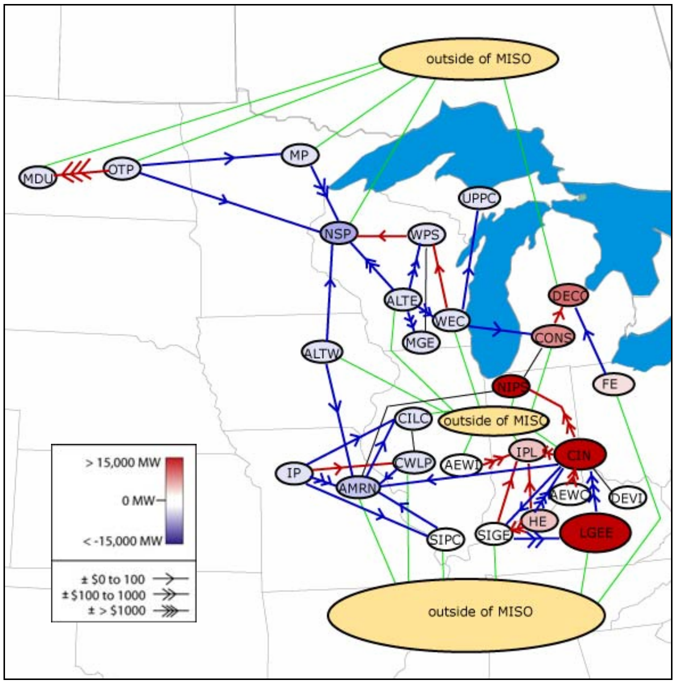


Figure EX-5. Congestion Revenue in Optimized MISO System, July 7, 2003 Case

To place the congestion revenues in perspective, consider that the value for total congestion revenues, nearly $230,000/h, is on the order of 20 percent of the value of the variable production costs, which is about $1,100,000/h[6]. This markup indicates that congestion does have a considerable measure, and it would be worth looking into opportunities to increase transmission capacity at proper locations[7]. In terms of market operation and settlement, it is important to

---

[6] For a more complete perspective, it would be valuable to compare congestion costs with those incurred in the base case. Unfortunately, it is impossible to estimate the economic impact of the congestion in the base case because we do not know the original schedules or which transactions that were curtailed to ensure secure operation. One of the benefits of a competitive, LMP-based market is that congestion and congestion revenues are made transparent.

[7] A careful study is needed to determine the benefit of transmission expansion, which should be judged over many dimensions including a reduction in production costs. High congestion revenues serve as a flag to justify and direct transmission studies, but are not a direct measure of the possible benefits of enhancements.

note that these congestion revenues are disbursed to those with financial transmission rights, which can mitigate financial burdens introduced by congestion.[8]

Conclusions and Next Steps

This report has begun to examine important aspects of the evolving MISO wholesale electricity market based on what can be known in advance of its opening. We confirm expectations that centralized dispatch of competitive generator offers will likely lead to production cost savings compared to the current, more decentralized system of dispatch of generation in the Midwest. We also illustrate how reliance on centralized dispatch can provide greater transparency on the patterns and cost of congestion in the Midwest.

We emphasize, in closing, that this study does not draw conclusions on the total impact of expected MISO operations in the Midwest and on surrounding areas. This study has focused on two individual snapshots of past operations and of necessity has made assumptions regarding the behavior of generators (and loads) in the areas adjacent to the MISO footprint. This focus is short-term and does not consider longer-term impacts from the creation a transparent, competitive, wholesale market in the Midwest. For example, we do not consider improved generator availability, improved heat rates, optimal maintenance scheduling, more aggressive lowering of input costs, especially fuel and labor, and the discipline imposed by new entry by newer low cost generating technologies. Similarly, many other aspects of the operation of such a market, such as start-up costs and allocation and settlement of FTRs, should be included in a complete assessment of the costs and benefits of this market.

In this regard, we are hopeful that these study findings will inspire others to probe these issues in greater detail to add to and provide greater context for the initial efforts presented in this report.

[8] For example, a particular allocation of FTRs could return all of the congestion revenues to those who paid premiums for energy due to congestion.

1. Introduction

In March 2005, the Midwest Independent System Operator (MISO) will begin operating the first-ever wholesale market for electricity in the central and upper Midwestern portion of the United States. Region-wide, centralized, security-constrained, bid-based dispatch will replace the current system of decentralized dispatch by individual utilities and control areas. The wholesale market will include both real-time and day-ahead electricity products. Locational marginal prices (LMPs) will be used to send participants a market-based measure of the value of congestion on the system. Financial transmission rights will be created to compensate holders for the congestion revenues that accrue from the difference between the price for power (i.e., its LMP) at its delivery point and the price for power at its source.

Consumers, generators, and government are justifiably concerned about the potential consequences (both negative and positive) of such a major change in the organization and operation of the bulk power system in the Midwest. Among other things, they would like to know:

1. What will be the net impact of changes in generation dispatch on total production costs? How will these changes be distributed geographically?
2. What wholesale prices (LMPs) will result from centralized dispatch of generation in the Midwest?
3. What will these LMPs reveal about the nature and patterns of congestion in the Midwest?
4. What will be the effect of using LMPs to, in effect, put a price tag on congestion?

This report addresses these questions based on what can be known in advance of the opening of the MISO wholesale electricity market. The analysis in this report was prepared for the U.S. Department of Energy (DOE) by an interdisciplinary team drawn from DOE's Lawrence Berkeley National Laboratory, the Federal Energy Regulatory Commission (FERC), and the Energy Information Administration (EIA).

Of necessity, our analysis is speculative because it must be based on assumptions about how participants will act once the market opens. As a starting point, the analysis assumes that the market works as intended: it is cost minimizing, reliable, and competitive. This assumption is an appropriate baseline against which to identify market design issues of potential concern before the market opens; it can also guide market-performance assessments after the market opens.

The analysis focuses on how the operation of generators may change under centralized dispatch. We analyze a stylized example of the changes by comparing a single, actual state of dispatch (4 p.m., July 7, 2003) taken from MISO's state estimator to the modeled performance of centralized dispatch under same conditions but that seeks to minimize the total system cost of production, using estimated cost data collected by the EIA.

Although our analysis offers important insights into how the MISO market could operate when it opens, we address only questions that can be examined by considering changes in generator dispatch alone. We do not address the net benefits or costs of creating a wholesale market in the Midwest A comprehensive assessment of net benefits would require many more snapshots of market behavior over a much longer study period. It would examine changes generator availability, heat rates, maintenance scheduling, impacts on input costs, especially fuel and labor, and the discipline imposed by new entry by newer low cost generating technologies. It would also require an assessment of the start-up costs associated with establishing the market. And, it would have to investigate the allocation, trade, and ultimate settlement of congestion revenues associated with financial transmission rights. Other studies have addressed some of these issues; we compare relevant aspects of these studies to our findings.[9]

This report is organized in five sections including this introduction, plus two appendices:

- **Section 2** describes the **methods and data** used for our analysis, including the critical role played by MISO in providing us with a system model and by EIA in providing us with information on generator production costs.
- **Section 3** presents our **findings** on changes in production costs and the range and distribution of LMPs as well as our preliminary observations on the nature and patterns of congestion.
- **Section 4** describes the results of two **sensitivity analyses**: the sensitivity of our results to the definitions of MISO's membership and to different load and electrical data.
- **Section 5** describes important **caveats and limitations** of this work and discusses how they might be addressed.
- **Appendix A** compares our findings to relevant aspects of **other recent studies of MISO**.
- **Appendix B** lists the names and abbreviations of all the control areas/power companies referred to in this report.

---

[9] DOE. 2003. *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Design*. report DOE/S-0138. April 30.
and
MISO. 2004. *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*. March 26.

2. Estimating the Impact on MISO of Centralized Generation Dispatch and Calculation of LMPs

2.1 Approach

This study examines the potential impact on MISO of central dispatch and LMPs by comparing how the system actually operated in the recent past to how it might have operated under central dispatch. Both the historical and hypothetical cases share the same defining data:

- Load,
- Generator availability (commitment) and production characteristics (heat rate and fuel cost),
- Grid configuration and constraints, and
- Net imports from outside MISO.

For the actual system operation case, we use data from a single, past state of dispatch (4 p.m., July 7, 2003). The hypothetical case is created by dispatching generators to minimize the MISO-wide cost of meeting the same load, given the actual historical generation commitment, grid configuration, and net imports. The results show:

- Generator dispatch,
- Line flows,
- Total system variable operating cost,
- Locational marginal prices (separated into energy, losses and congestion components), and
- Congestion revenues.

The hypothetical case represents an idealized version of the new competitive wholesale electricity market that MISO is striving to create. If MISO's market were perfectly competitive, generators would minimize system cost, and competition would replicate the outcomes of centralized economic dispatch based on production costs. In other words, our analysis can be viewed as comparing current market operations to a perfectly competitive wholesale market. If the market is not competitive and generators are able to bid above their production costs and set the market clearing price, then our results will tend to over-state the benefits of centralized dispatch.

Historically, generators were dispatched to meet the relevant costs and constraints of their individual owners, so power flows were optimized in a decentralized way. In the hypothetical case, generators are dispatched to minimize the total system variable cost of production, regardless of who incurs it. As a result, power moves within and across control areas as needed to reduce total variable production costs, subject to the capability of the transmission system to support these shipments. Our analysis examines the changes that result from this hypothetical change in operation.

The hypothetical case relies only on generation that was actually committed (and was operating) in the actual or base case snapshot provided by MISO. This is a restrictive assumption because it means that generation not committed the base case is not available to serve load in the hypothetical case; similarly, all generators that were committed in the base are held on line, possibly at very low load in the hypothetical case. However, this assumption may be appropriate to the extent that generation committed is the base case was committed in part to meet reliability criteria. If this were the case, then holding these generators on-line in the hypothetical case can be viewed as one way to ensure security or reliability constraints are respected by our hypothetical re-dispatch.[10]

The historical period chosen for study is particularly important because the comparisons are for a single hour of a selected day. Had the study been performed for every hour of a representative year, the time period chosen would have had less influence on the results than a single hour's operation does. The historical period used in this study is discussed below in subsection 2.3. We address the impact of the time period used in Section 4 in a sensitivity case that shows the results of using a different reference case.

This study uses the PowerWorld © Optimal Power Flow (OPF) tool to calculate the costs of production resulting from centralized dispatch and the LMPs and congestion revenues that result from this dispatch[11]. The tool models the electricity grid using a full AC power-flow calculation. Reliance on a full AC power-flow model, brings our analysis as close to reality as possible. We do not use alternative power-flow models because they exhibit one of the following limitations:

- They do not capture the behavior of electricity power flows in a network (a limitation of the "transport" representation commonly used in multi-area production cost models)

  or
- They do not capture voltage and reactive-power considerations, which are important for ensuring system reliability and which can affect prices (a limitation of DC power-flow models).

PowerWorld's advantage over a DC power-flow model is that it uses load-tap-changing (LTC) transformers and variable shunt reactors to enforce voltage set points in the network, it accounts for reactive power in transmission constraints and enforces generator reactive-power constraints and generator set-point voltages. However, it has the limitation that it does not use generator redispatch to enforce voltage constraints. All of these may directly or indirectly affect prices and optimal centralized system dispatch.

In this model we enforce all the transmission line capacity limits that appear in the state estimator data. In operation, MISO may not perform a full OPF, but instead enforce flow constraints on pre-defined flowgates. We discuss the bias of a more restrictive full OPF in Section 5.

[10] The same cannot be said of transmission lines; we allowed re-dispatch up to the rated limits of the lines, but we did not have information to determine whether these limits incorporated security or reliability constraints.

[11] Because our data derives from a historical condition that we assume was secure with the allocated resources, we did not perform a more sophisticated security constrained OPF (SCOPF) including unit commitment.

2.2 Locational Price and Congestion Revenue

The LMP of energy is the lowest system-wide cost of supplying or consuming one more unit of power at a specific location.[12] When a system is free of losses and congestion, generators are dispatched in merit order, starting with the lowest-marginal-cost unit and adding progressively more expensive units until demand is met. In this case, all locations are subject to the same marginal price, which is the marginal cost of the last generator dispatched to meet demand. When different generators or consumers impose differential losses or congestion on the system, LMPs reflect the unique costs (savings) each imposes on the system by its impact on congested lines (and losses).

LMPs are computed from the solution of the OPF model: they are the shadow prices (Lagrangian multipliers) associated with small changes in injections at generator and load buses. PowerWorld has an AC optimal power-flow tool that determines the least-cost generator dispatch while enforcing:

- Generator capacity limits,
- Line and security limits,[13] and
- Energy balances (demand = generation – losses + net imports).

Congestion revenue for each line is calculated as the congestion component of the LMP at the sink, less the congestion component of the LMP at the source, times the flow. Congestion revenue values are usually positive, representing power flow from low cost to high costs, but they can be negative, meaning that increasing consumption (or decreasing generation) at a given point can reduce overall system costs by relieving congestion. The line-congestion revenues calculated for our cases were summed within control areas and for MISO as a whole.

2.3 Data

Two primary data sources were used in this study. First, MISO provided the project team with a snapshot of its system operation at 4 p.m. on July 7, 2003. The snapshot was prepared by MISO's state estimator and shows generation loading and line flows for every electrical element of the MISO system as well of many of the other control areas interconnected with MISO. Second, EIA provided the project team with estimated generator production cost data derived from the EIA Form 860. Significant effort was involved in aligning these two data sources for use in the study.

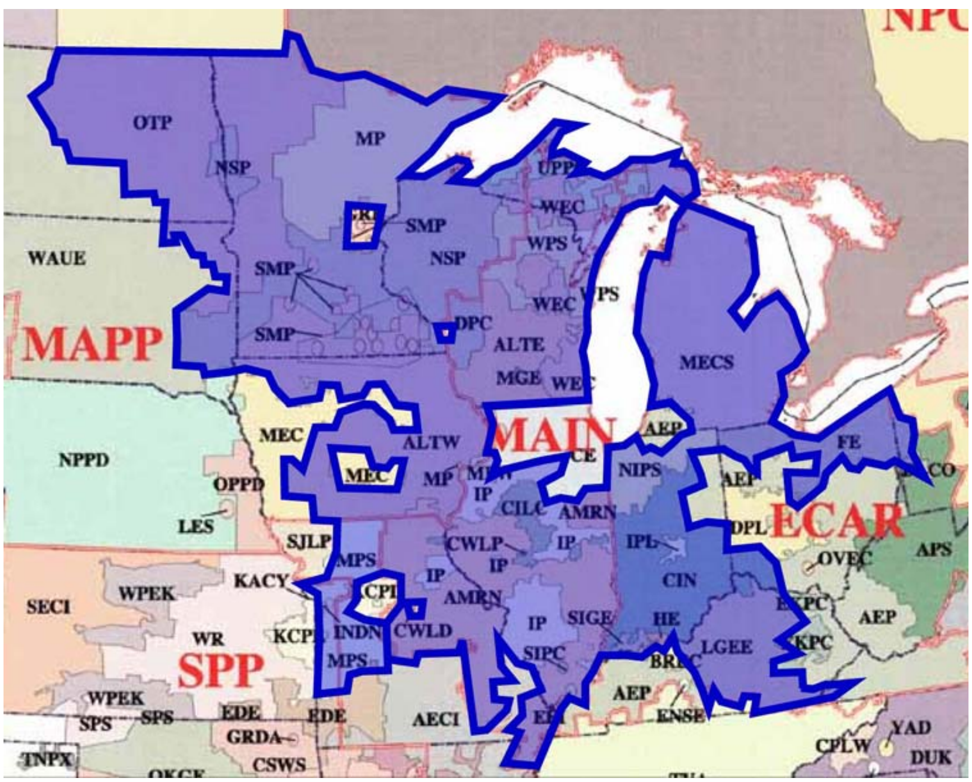
---

[12] See for example: Schweppe, Fred et al. 1988. *Spot Pricing of Electricity*. Kluwer Academic Publishers (page 32, equation 2.1.1).

[13] PowerWorld reports voltage violations consistent with its reliance on a full AC power-flow calculation. However, PowerWorld does not use this information to adjust generator outputs to ensure that voltages remain within specified tolerances. LTC transformers maintain voltage set points in the network.

A major issue for our analysis is the evolving membership of MISO. The make-up of MISO is important because imports from or exports to control areas and utilities outside of MISO are held fixed in our analysis. As noted, we analyze how dispatch might change by centrally dispatching all generators that are within MISO; by convention, we do not allow any generators outside of MISO to change output. This convention implicitly assumes that trade outside of MISO and trade between MISO and outside regions are both roughly independent of the centralized market dispatch. (Alternatives to this reliance on the historical trade pattern include calculation of a global internal and external optimum in which a "hurdle rate" is applied to trade between MISO and other regions. This is discussed in Section 5). As of April 2004, MISO identified 27 control areas as expected members of its market[14]. The members and information on their loads, native generation, and original interchanges are listed in Table 2-1 and shown in Figure 1. The current members make up an electrically, if not geographically, contiguous portion of the Eastern Interconnection, spanning 11 states and three NERC reliability regions. MISO is the first market to attempt multi-reliability-region operation.

Membership in the MISO-run market is voluntary and has changed in the past and may change again. We explore the potential impact of membership changes on our analysis using a sensitivity case in Section 4.



control area map source: Bechtel

Figure 1. Midwest ISO Geographic Footprint

[14] As of this writing, MISO expects Great River Energy (GRE) to be part of the market.

Table 2-1. Base-Case Control-Area Load, Generation, and Imports/Exports, July 7, 2003

Area Name	Generation Capacity (MW)	Base-Case Generation (MWh)	Load (MWh)	Import (-)/ Export(+) (MWh)
Total Non-MISO Control Areas	**383,964**	**239,917**	**227,316**	**7,760**
Total MISO Control Areas	**123,005**	**80,108**	**85,953**	**-7,760**
Allegheny Energy - Wheatland IPL[15]	268	0	0	-17
Allegheny Energy - Wheatland CIN	268	0	0	-1
Alliant East	2,847	1,589	1,946	-430
Alliant West	5,270	2,343	3,004	-759
Ameren	15,710	10,704	9,480	1,062
Central Illinois Light Co.	1,290	679	1,082	-415
Cinergy Corp.	13,066	9,328	9,730	-588
Consumers Energy Company	9,542	6,337	6,383	-253
City WL&P-Springfield	614	398	396	1
Detroit Edison Company	11,217	7,582	8,894	-1,462
Duke Energy	640	0	0	0
First Energy	13,427	8,144	9,342	-1,362
Hoosier Energy Rural Electric Coop.	1,498	929	540	340
Illinois Power	5,544	4,270	3,901	309
Indianapolis Power & Light Co.	3,436	2,564	2,490	20
LG&E Energy	8,214	6,230	5,775	339
Montana-Dakota Utility Co.	235	144	389	-270
Madison Gas & Electric Company	590	301	605	-316
Minnesota Power Co.	2,444	1,140	1,244	-162
Northern Indiana Public Service Co.	3,873	2,167	3,149	-1,040
Northern States Power Co.	9,319	5,710	7,099	-1,566
Otter Tail Power Co.	1,545	1,276	1,250	-25
Southern Indiana Gas & Electric	1,962	1,456	1,515	-77
Southern Illinois Power Coop.	473	275	204	63
Upper Peninsula Power Co.	194	148	238	-96
Wisconsin Electric Power	6,798	4,307	5,137	-928
Wisconsin Public Service Coop.	2,721	2,089	2,161	-129

[15] The Allegheny Energy Wheatland IPL and Allegheny Energy Wheatland CIN generation-only control areas have been decertified by ECAR and the Wheatland facility generation is now metered to the CIN control area.

Table 2-2. Number of Electrical Components in MISO Model, July 7, 2003

Components	Number within MISO footprint	Number in entire model
Control Areas	27	106
Buses	8,926	27,798
Lines/Transformers	11,434	34,981
Loads	6,428	20,520
Generators	1,026	3,680

As noted, MISO provided an electrical model of their system from their state estimator for actual operation at 1600 h (4 p.m.) on July 7, 2003. The model represents a much larger area than was actually assumed to be in the MISO because MISO models and tracks activity on the grid that is outside of what it controls but that can have an impact on its operations. See Table 2-2.

EIA provided estimated production cost information on the generators within MISO. For each generator, the information consists mainly of fuel cost, full-load heat rate, and a small amount for variable operations and maintenance costs. Production information was not available for all generators represented in the MISO model for the July 7, 4 p.m. snapshot. However, the absence of these data has only a very minor impact on our findings. More than 50 percent of generators within the MISO footprint were matched with to EIA cost data, representing 77 percent of total capacity within the region and about 98 percent of the capacity that was on line and generating electricity during the July snapshot period. For the two percent of generation for which production cost information was not available, we fixed generation in the hypothetical case to match that recorded in the July snapshot (Table 2-3).

Table 2-3. Generation Capacity within MISO Footprint in the MISO Model, July 7, 2003

MISO Generation Capacity	Number of Units	Capacity (MW)	Percent of Total Capacity	Percent of MISO Load
Total	1,026	123,005	-	-
On line	683	97,624	79%	114%
Available for Re-dispatch	558	95,300	77%	111%
Fixed Output	124	1,964	2%	2%

2.4 Summary of the Study Design

Table 2-4 summarizes the core elements of our study's design and notes, in the "Comments" column, key details that we discuss in our analysis of results.

Table 2-4. Summary of Core Elements of Study

Study Element	Description	Comments
Objective	Compare historical dispatch to hypothetical, bid-based centralized dispatch at 1600 (4 p.m.) on July 7, 2003	Sensitivity analysis considers alternate loads and generation based on historical dispatch at 13:19 on February 18, 2004.
Tool	AC OPF (PowerWorld)	Addresses loop flows and voltage/reactive power issues that cannot be captured by transport or DC power-flow tools.
System Model	State estimator snapshot provided by MISO	Includes a significant portion of Eastern Interconnection (~30,000 nodes, total, of which ~9,000 are within MISO footprint).
Generator "Bids"	Generator production costs provided by EIA	Generation fixed for 2% of load for which cost data were not available.
Key Study Conventions	Generation external to MISO is fixed	Sensitivity analysis considers different membership for MISO (2003 vs. 2004).
	Voltage limits not enforced through redispatch	Transformer load-tap changes are used to enforce voltage set points. Generator reactive power limits enforced.
Analysis	Generator dispatch, line flows, system variable production cost, LMPs, congestion revenues aggregated by control area	Major congested paths are identified within control areas.

3. Findings from the July 7, 2003 Case

In this section we compare the base-case historical dispatch from the July 7, 2003 MISO state-estimator solution to the hypothetical case of centralized competitive market-based dispatch. The subsections below describe the changes, from the base case to the competitive-market case, in generation and power flow and system operating costs; we also describe LMPS in the competitive-market case, and a description of congestion and associated congestion revenues. The results show that centralized dispatch in a perfectly competitive market results in a significant decrease in variable operating costs and that the optimal use of network resources results in congestion.

3.1 Generation and Power Flows

During the optimization of the centralized dispatch competitive market case, load was kept constant, as were net interchanges between areas not in MISO; generation and flow on transmission lines within MISO, however, were allowed to move. Generation under central dispatch increased 84 MW compared to its historical value of 80,108 MW. The fact that the total generation change was small is not surprising because the load was held constant. The absolute increase in generation matched the observed increase in electricity consumed by line loss. System losses increased because, during optimization, load was being met by lower-cost generation that was farther away; flows between control areas within the MISO increased by more than 2000 MW. Losses increased as electricity was shipped over longer distances, and a small amount of extra generation was needed to cover these losses.

Although the net change in generation was not great from the base case to the competitive-market case, the change in generation at some plants was large. Of the 558 plants that were allowed to change power output, 304 increased production, 167 decreased production, and 87 experienced no change in production. The amount of change by plant, ordered by most positive to most negative, is shown in Figure 2. The majority of coal-burning generators increased generation whereas the majority of natural-gas generators decreased or experienced no change. Table 3-1 summarizes the changes in generation plants by fuel type. Figure 3 and Figure 4 depict the change in generation between the base case and the OPF solution for different fuel types, in both MW and percent change per plant from the base case.

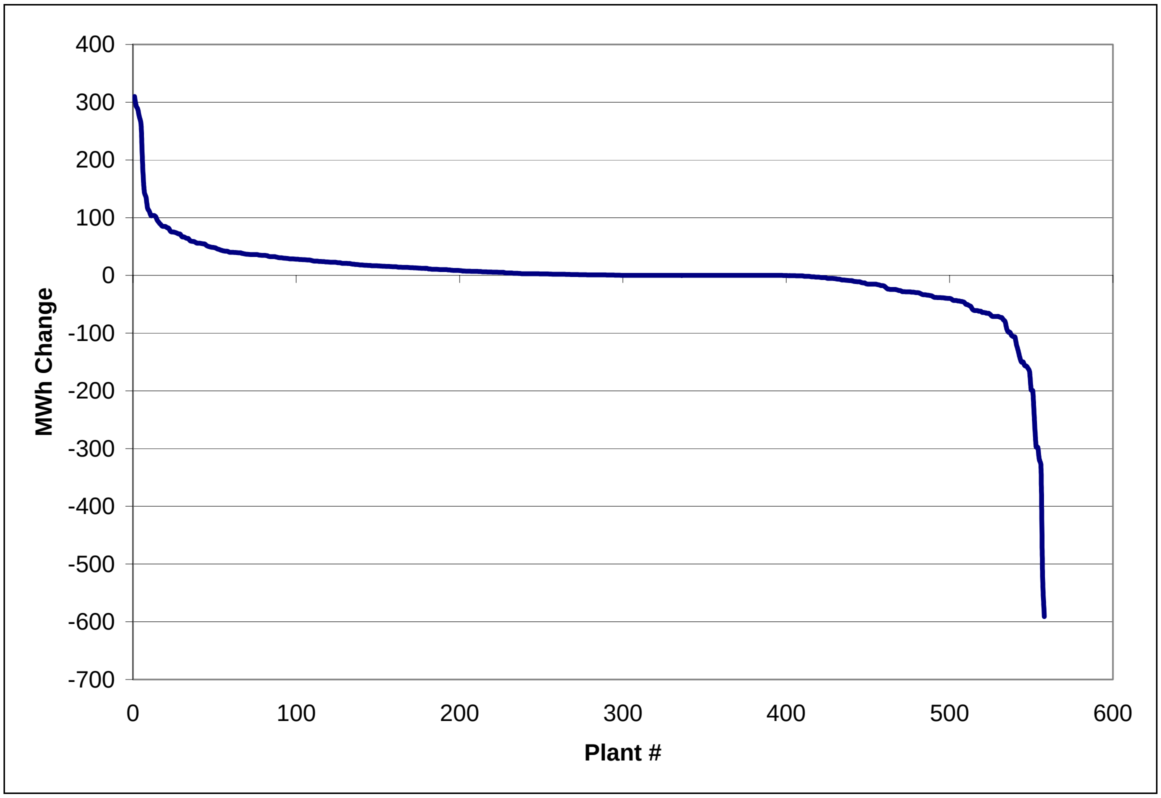


Figure 2. Generation Change in Redispatchable MISO Generators from Base Case to OPF Case, July 7 Snapshot

Table 3-1. Generation Plant Output Changes from Base Case to OPF Case, by Fuel Type

	% of Total # of Plants (that were able to change)	% of Total Capacity (that were able to change)	Change in generation (MWh)	% plants with Decreased generation	% plants with No Change	% plants with Increased Generation
Coal Plants	45%	66%	5,403	11%	9%	80%
Gas Plants	23%	10%	-3,520	69%	22%	9%
Hydro/ Nuclear Plants[16]	11%	10%	705	0%	17%	83%
Other Plants[17]	21%	13%	-2,504	44%	22%	34%

[16] We assume the full rated capacity of units is available for dispatch to serve load, however actual capacity available may be limited for operational reasons.
[17] Includes petroleum, wood, and pumped storage.

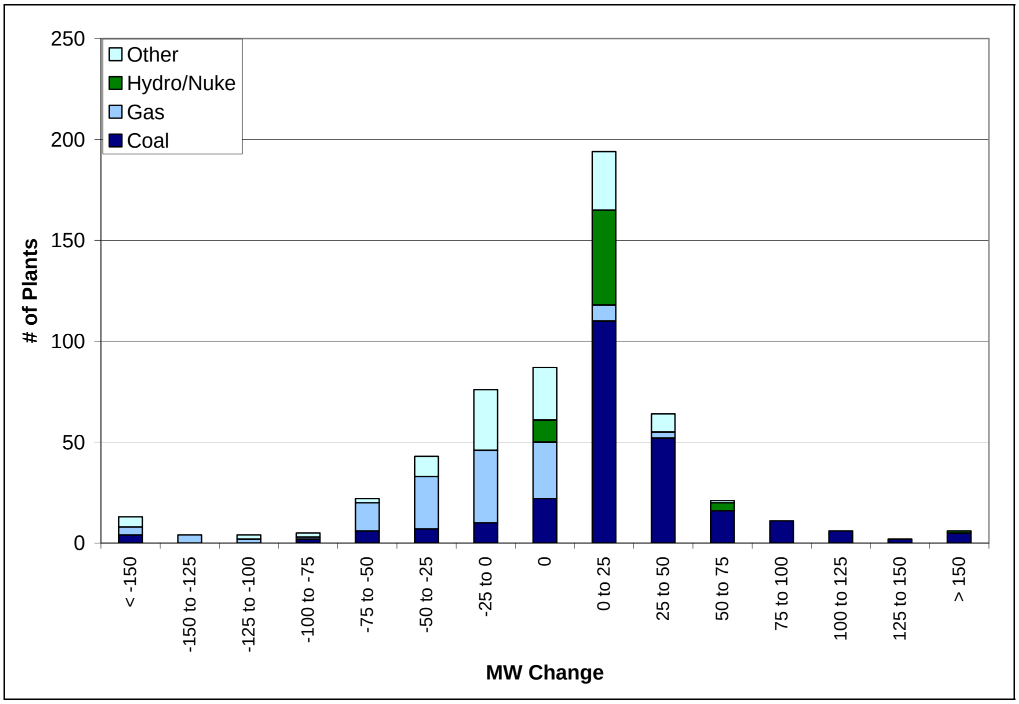


Figure 3. Change in Generation for Plants that were Allowed to Change between Base Case and OPF Case

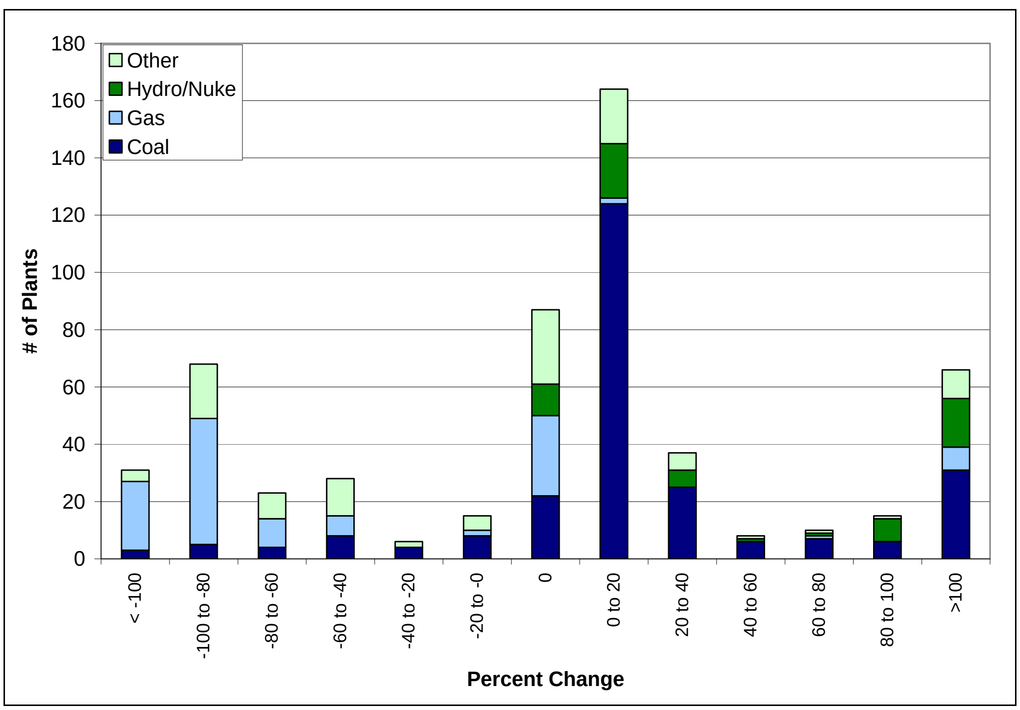


Figure 4. Percent Change in Generation for Plants that were allowed to Change between Base Case and OPF Case

The geographic layout of these changes can be seen below in Figure 5 and Figure 6. The circles represent existing NERC control areas[18] that are expected to participate in the MISO market, the black lines represent power lines between MISO control areas, and the green lines represent electrical connections between MISO control areas and control areas outside of the MISO system. For the most part, the locations of the control areas on this map closely correspond to their actual locations, but in some cases the geographic discontinuity of a control area, such as Wisconsin Electric Power Company (WEC), is not represented on this map. This schematic map will be used several more times in this text. These same explanations apply each time.

The first map, Figure 5, shows absolute changes in generation by control area; the second map, Figure 6, displays the percent change in generation between the base-case historical and optimized competitive-market systems. The absolute change in control-area generation ranges from a roughly 1,000-megawatt (MW) increase (in the Detroit Edison Company area) to a more than 1,800 MW decrease (in the First Energy area). The change in generation was concentrated in the eastern part of the MISO geographical area. The percent change in generation is more spread out than the absolute change; this value depends on how much capacity each control area has to begin with; there is no geographic pattern to the variation in control-area capacity.

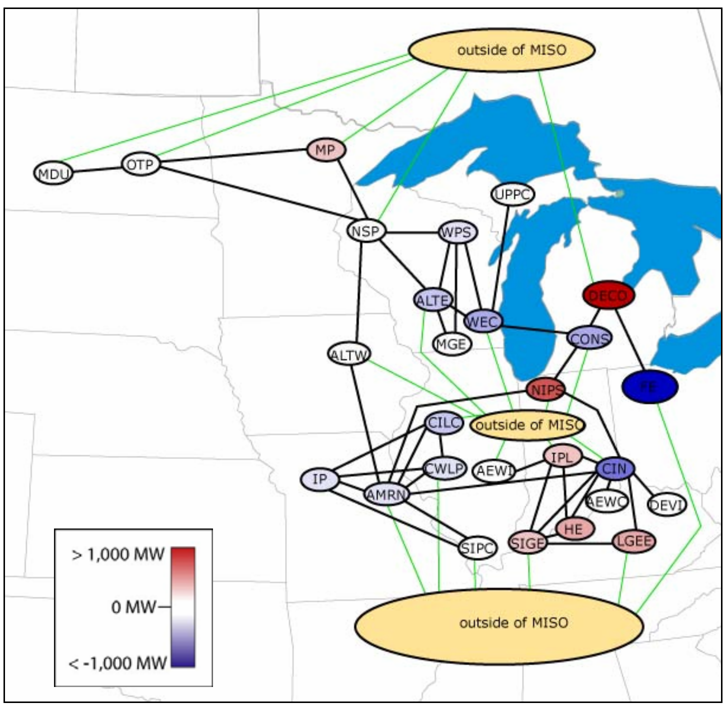


Figure 5. Absolute Change in Control-Area Generation between Historic System and Optimized System

[18] A few areas – Consumer Energy Company, Detroit Edison Company, and Montana-Dakota Utility Company – are not distinct NERC control areas but were identified as separate areas in our model.

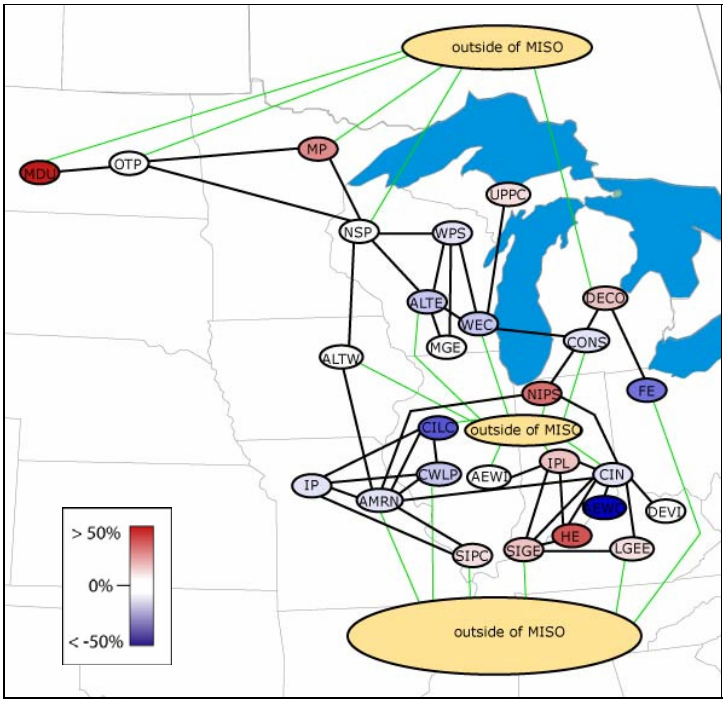


Figure 6. Percent Change in Control-Area Generation between Historic System and Optimized System

The data displayed in the maps above are also shown in Table 3-2.

Table 3-3 shows the changes from the base case to the OPF redispatch in control-area imports and exports. Because load is held constant in the OPF, the differences in generation and in imports and exports are highly correlated. If generators increase production in a control area, this extra power is exported; likewise, if generation decreases in a control area, more power must be imported to meet the stranded demand. Small differences between the magnitude of change in generation and interchange result from losses.

Power flows in the system changed along with changes in generation. As mentioned above, system losses (and thus generation) increased because power was being shipped over longer distances; flows between control areas within MISO increased by more than 2,000 MW.

Table 3-2. Change in Control-Area Generation between Historic System and Optimized System

Control Area	Base-Case Generation (MW)	OPF Generation (MW)	Difference in Generation (MW)	Difference in Generation %
First Energy	8,144	6,331	-1,813	-22%
Cinergy Corp.	9,328	8,886	-442	-5%
Wisconsin Electric Power	4,307	4,013	-294	-7%
Consumers Energy Company	6,337	6,047	-289	-5%
Central Illinois Light Co.	679	493	-185	-27%
Alliant East	1,589	1,485	-104	-7%
Ameren	10,704	10,622	-82	-1%
Illinois Power	4,270	4,205	-65	-2%
City WL&P-Springfield	398	372	-26	-7%
Wisconsin Public Service Coop.	2,089	2,065	-23	-1%
Allegheny Energy - Wheatland CIN	0	0	0	0%
Duke Energy	0	0	0	0%
Allegheny Energy - Wheatland IPL	< 1	< 1	< 1	-45%
Madison Gas & Electric Company	301	303	1	0%
Upper Peninsula Power Co.	148	156	8	5%
Southern Illinois Power Coop.	275	294	20	7%
Alliant West	2,343	2,366	22	1%
Northern States Power Co.	5,710	5,758	48	1%
Otter Tail Power Co.	1,276	1,328	52	4%
Montana-Dakota Utility Co.	144	204	60	42%
Southern Indiana Gas & Electric	1,456	1,673	217	15%
Indianapolis Power & Light Co.	2,564	2,832	267	10%
Minnesota Power Co.	1,140	1,413	273	24%
Hoosier Energy Rural Electric Coop.	929	1,247	318	34%
LG&E Energy	6,230	6,625	394	6%
Northern Indiana Public Service Co.	2,167	2,803	637	29%
Detroit Edison Company	7,582	8,671	1,088	14%

3.2 Variable System Operating Cost

Despite the slight increase in generation in the OPF case, system operating cost decreased substantially as a result of optimization. The calculated system cost is not total cost because fixed costs are excluded. By definition fixed costs are those (such as property taxes and long-term

Table 3-3. Change in Control-Area Imports and Exports between Historic System and Optimized System

Area Name	Base Case Import (-)/ Export (+) (MWh)	OPF Import (-)/ Export (+) (MWh)	Difference in Exchange (MWh)	% Difference in Exchange
First Energy	-1,362	-3,179	-1817	133%
Cinergy Corp.	-588	-1,039	-451	77%
Consumers Energy Company	-253	-536	-283	112%
Wisconsin Electric Power	-928	-1,210	-282	30%
Central Illinois Light Co.	-415	-603	-188	45%
Alliant East	-430	-534	-104	24%
Ameren	1,062	961	-101	-10%
Illinois Power	309	243	-66	-21%
City WL&P-Springfield	1	-26	-27	-2700%
Wisconsin Public Service Coop.	-129	-142	-13	10%
Allegheny Energy - Wheatland IPL	-17	-19	-2	12%
Allegheny Energy - Wheatland CIN	-1	-2	-1	100%
Duke Energy	0	0	0	-
Madison Gas & Electric Company	-316	-315	1	0%
Upper Peninsula Power Co.	-96	-89	7	-7%
Southern Illinois Power Coop.	63	85	22	35%
Alliant West	-759	-736	23	-3%
Northern States Power Co.	-1,566	-1,532	34	-2%
Otter Tail Power Co.	-25	23	48	-192%
Montana-Dakota Utility Co.	-270	-216	54	-20%
Southern Indiana Gas & Electric	-77	134	211	-274%
Indianapolis Power & Light Co.	20	281	261	1305%
Minnesota Power Co.	-162	106	268	-165%
Hoosier Energy Rural Electric Coop.	340	651	311	91%
LG&E Energy	339	719	380	112%
Northern Indiana Public Service Co.	-1,040	-408	632	-61%
Detroit Edison Company	-1,462	-377	1085	-74%

debt service) that cannot be affected by short-term changes in operations; these costs are not relevant to short-term cost minimization. The difference in operating costs between the decentralized base case and the centralized-dispatch optimized case represents the production-cost savings that centralization would entail.

Variable system operating cost was calculated in both the base case and the optimized case by multiplying the generator cost (mainly fuel cost per MWh) by the amount of generation.[19] Because we did not have complete cost data for every generator (in particular, fixed cost information was lacking), our calculated costs represent variable costs.

The total variable cost of production in the base case for the generators for which we had cost data (which cover approximately 91 percent of MISO area load) was $1,440,574/h. There was a decrease of $327,417/h in variable system cost between the historical case and the optimized case, which amounts to about 20 percent of base-case variable system cost. This is a significant decrease as a result of shifting to centralized competitive-market dispatch. The change is not uniform throughout the MISO region, however. Table 3-4 lists the by control area. (Although control areas do not have their traditional importance in the central-dispatch case, we use them to organize the data geographically.)

The largest decrease in production costs occurs in the First Energy control region and is consistent with the values shown in Table 3-2 and 3-3 that show the largest decrease in generation and increase in imports. The majority of this large decrease in generation and cost was at the petroleum units where fuel prices were nearly $4 more than at the coal plants in the region. Some of the petroleum plants had significantly higher operating costs than other generators in the area. Similar observations can be made for the other control areas. In the Cinergy Corp. control area, the natural gas plants, whose fuel prices were high, decreased output. The control area with the largest increase in system cost, Detroit Edison, owes most of this increase to greater output at several coal plants.

[19] The generation costs were provided to us as cost curves, so the equation used to calculate system cost was: (A + B*P + C*P^2 + D*P^3)*FC where A,B,C and D are constants; P is the power output of the generator in MW; and FC is fuel cost.

Table 3-4. Control Area Variable Operating Cost[20]

Control Area	Base Case System Cost ($/h)	OPF System Cost ($/h)	Total Change in System cost ($/h)	% Change in System Cost
Total	**$1,440,574**	**$1,113,157**	**-$327,417**	**-23%**
First Energy	$396,908	$195,287	-$201,621	-51%
Cinergy Corp.	$159,317	$112,378	-$46,940	-29%
Ameren	$135,515	$107,213	-$28,302	-21%
Consumers Energy Company	$122,986	$98,595	-$24,391	-20%
Wisconsin Public Service Coop.	$31,544	$21,553	-$9,990	-32%
Alliant West	$34,560	$26,012	-$8,548	-25%
Alliant East	$27,624	$20,658	-$6,966	-25%
Northern States Power Co.	$50,880	$45,097	-$5,783	-11%
Wisconsin Electric Power	$44,878	$39,849	-$5,029	-11%
Illinois Power	$65,177	$60,679	-$4,499	-7%
City WL&P-Springfield	$8,773	$4,848	-$3,926	-45%
Central Illinois Light Co.	$11,897	$8,697	-$3,199	-27%
Montana-Dakota Utility Co.	$4,152	$2,709	-$1,442	-35%
Southern Indiana Gas & Electric	$21,573	$20,226	-$1,347	-6%
Indianapolis Power & Light Co.	$36,727	$35,801	-$926	-3%
Hoosier Energy Rural Electric Coop.	$14,588	$13,730	-$858	-6%
Upper Peninsula Power Co.	$2,404	$2,234	-$171	-7%
Allegheny Energy - Wheatland CIN	$0	$0	$0	-
Duke Energy	$0	$0	$0	-
Allegheny Energy - Wheatland IPL	-$14	-$8	$6	45%
Madison Gas & Electric Company	$3,753	$3,770	$17	0%
Southern Illinois Power Coop.	$3,566	$3,843	$276	8%
Otter Tail Power Co.	$13,875	$14,447	$572	4%
Minnesota Power Co.	$12,651	$14,759	$2,108	17%
LG&E Energy	$95,454	$97,720	$2,266	2%
Northern Indiana Public Service Co.	$45,141	$55,033	$9,892	22%
Detroit Edison Company	$96,643	$108,026	$11,382	12%

[20] These values reflect production costs and should not be confused with the cost to serve control area load. The cost to serve load is a sophisticated calculation involving imports, exports, the allocation and treatment of financial transmission rights, and other transmission and administrative considerations. We do not estimate the cost to serve load in this report.

3.3 LMPs

Optimal power-flow algorithms, like the one used in this analysis, calculate LMPs at every bus within the specified system, in our case MISO. The average, non-load-weighted LMP of the entire system was $26/MWh. The average LMP of most individual control areas ranged from roughly $14/MWh to $38/MWh, with one area significantly outside this range at $59/MWh.

Table 3-5 lists these average LMPs along with measures of variation. Non-uniform LMPs within a region indicate transmission congestion, and to a lesser extent, the effect of losses. As we will note below, regions with significant differences in LMPs will have significant congestion revenues. The geographic distribution of these average prices is shown schematically by control area in Figure 7. The values in the map in Figure 7 range from an average LMP of $10/MWh to $40/MWh, with darker colors indicating a higher average. The Northern Indiana Public Service Co. (NIPS) control area is an exception, with an average LMP of $59. It is represented in Figure 7 as the large red circle to signify that it lies outside of the otherwise well-distributed range.

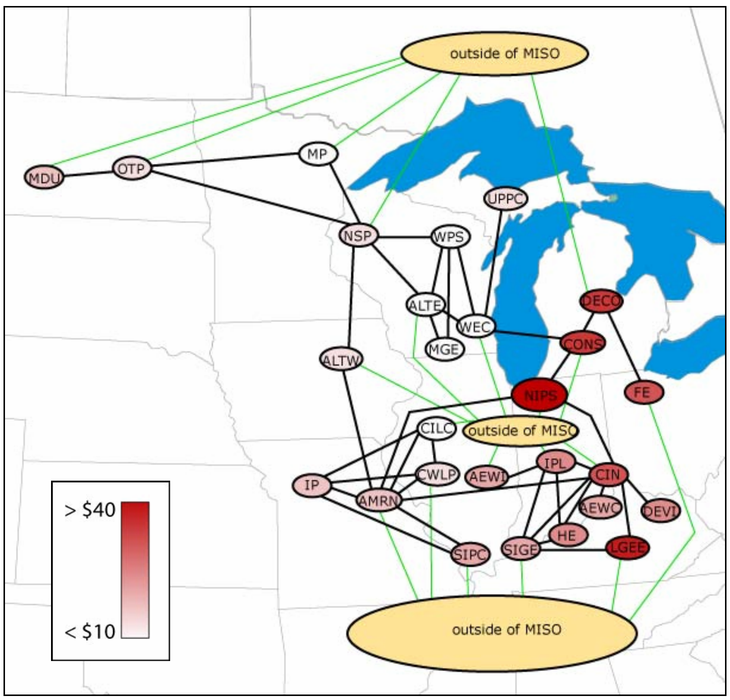


Figure 7. Average Control-Area LMPs at All Buses within the MISO System

Table 3-5. Average Control-Area LMPs

Area Name	Marginal Cost Average ($/MWh)	Marginal Cost Average Standard Deviation ($/MWh)	Coefficient of Variation (Standard Deviation/Average)
Northern Indiana Public Service Co.	$58.58	61.25	105%
LG&E Energy	$37.56	28.04	75%
Consumers Energy Company	$34.72	2.28	7%
Detroit Edison Company	$34.61	1.39	4%
First Energy	$33.06	0.78	2%
Cinergy Corp.	$31.30	13.55	43%
Hoosier Energy Rural Electric Coop.	$27.53	32.22	117%
Indianapolis Power & Light Co.	$27.21	1.77	7%
Duke Energy	$25.14	0.00	0%
Allegheny Energy - Wheatland CIN	$24.27	0.00	0%
Allegheny Energy - Wheatland IPL	$23.25	0.00	0%
Southern Illinois Power Coop.	$23.21	0.72	3%
Southern Indiana Gas & Electric	$22.76	3.60	16%
Ameren	$21.76	2.29	11%
Illinois Power	$20.22	2.66	13%
Montana-Dakota Utility Co.	$19.28	1.37	7%
Upper Peninsula Power Co.	$19.00	1.37	7%
City WL&P-Springfield	$17.77	0.17	1%
Alliant West	$17.64	0.99	6%
Northern States Power Co.	$17.26	0.83	5%
Otter Tail Power Co.	$16.39	2.38	15%
Central Illinois Light Co.	$15.95	1.18	7%
Minnesota Power Co.	$15.66	1.79	11%
Wisconsin Electric Power	$15.23	5.62	37%
Wisconsin Public Service Coop.	$15.22	1.12	7%
Madison Gas & Electric Company	$14.45	0.29	2%
Alliant East	$14.31	0.90	6%

The NIPS area has a high average LMP and standard deviation because of several extremely high-priced buses, caused by a congested line connecting this area to an area outside of MISO. We draw the readers attention to this point because trade between the MISO and areas outside the MISO is held fixed at the level noted in the state estimator snapshot in this study. Operation of the market may affect trade at the seams between markets, and a difference trade profile between markets might not cause these extreme prices along the boundary. We discuss more of the seams issue in Section 5.[21]

Figure 8 plots the percentage of total generation/load less than or equal to the value of LMP; this plot may be considered an "LMP duration curve," akin to more widely known load-duration curves. As an example of how reading these duration curves, consider the values at 60 percent of load/generation. At this level, 60 percent of the load is at LMPs less than $28/MWh, and 60 percent of the generation is at LMPs less than $22/MWh. The areas under the curves, scaled by the total load/dispatch, represent the payment made/received by the loads/generators. It makes intuitive sense that the difference in areas is roughly equal to the congestion revenues. If there were no losses and no congestion, the curves would be identical, and there would be no difference between them. Because there is congestion, the curves diverge. This plot simultaneously shows the difference in LMPs between loads and generation attributable to congestion and shows for approximate congestion revenues[22] as the area between the curves.

Monitoring the range of detailed *bus-level* LMPs is important although this value is not always included in other studies. Some studies focus on *average* LMPs, which can have a more direct impact on retail load pricing. The variation in LMPs indicates network congestion that could benefit from transmission enhancements if specific bottlenecks are persistent. Also, high prices may indicate exercise of market power or exploitation. This study does not address market power because we assume competitive, marginal-cost offers. In practice, however, market monitors will want to flag high prices and causes of congestion.

3.4 Congestion and Congestion Revenue

This section discusses network congestion and the resulting congestion revenues in the hypothetical competitive-market case. Although this discussion focuses on the valuation of congestion in the centralized-dispatch competitive market, it is important to note that congestion also occurs in traditional, non-market, non-centralized, and suboptimal dispatches. In fact, some of the limiting transmission lines in our competitive-market OPF study are also operating at their limits in the original state-estimator solution provided by MISO. Unfortunately, it is impossible to estimate the economic impact of the congestion in the state-estimator solution because we do not know the original schedules or which transactions that were curtailed to ensure secure operation. One of the benefits of the competitive market is that congestion and congestion revenues are transparent.

[21] The informed reader may also note that the geographical distribution of LMPs noted here do appear qualitatively different than that in other reports (see Appendix A). We discuss some of the possible reasons for this difference in Appendix A.
[22] Revenues are approximate because losses are not explicitly counted.

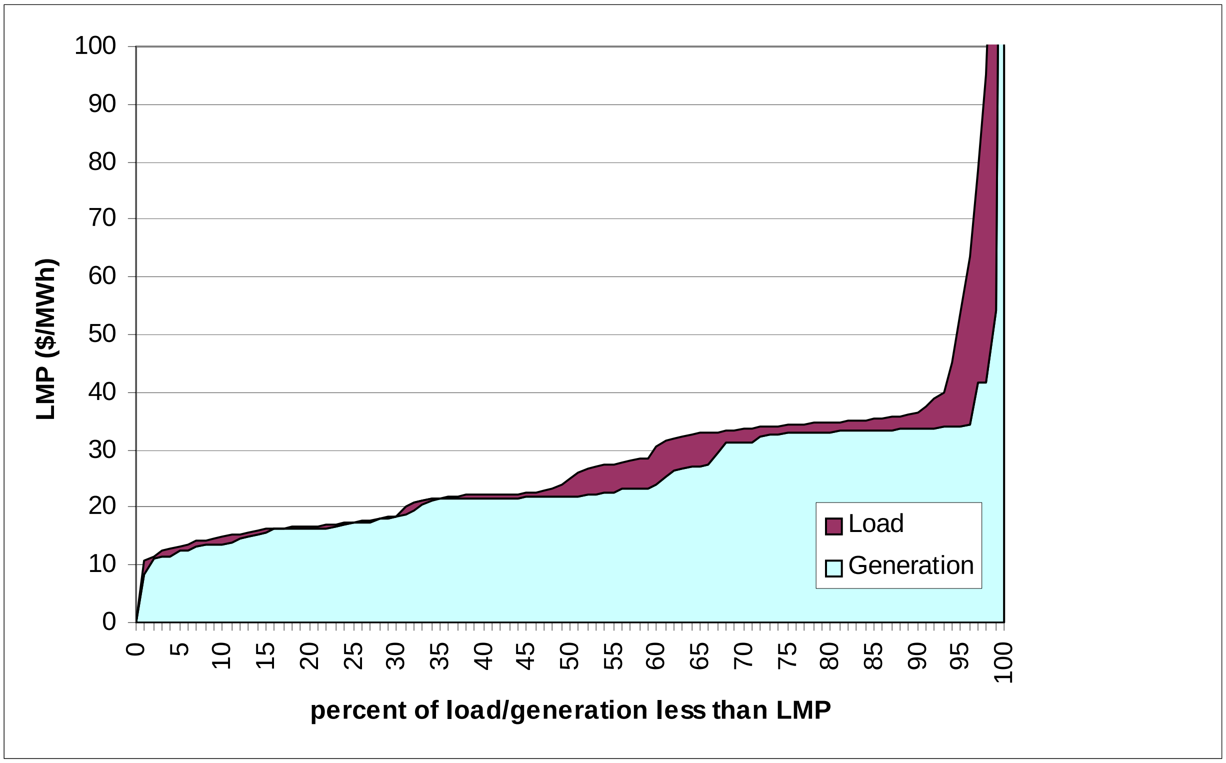


Figure 8. Percent of Load/Generation at Less Than LMP. The respective areas, scaled by total amount, represent the total load payments or generator receipts. The difference is a measure of congestion revenues.

In sum, the congestion revenues represent the total payments by loads in excess of the payments received by the generators, accounting for system losses. The ultimate impact of congestion revenues (increased load payments) cannot be assessed without detailed consideration of financial transmission rights. Simplistically, these rights will be available to loads, and will serve to effectively reduce their energy costs below what is indicated by the LMPs. A detailed analysis of financial transmission rights is not the purpose of this study and we do not attempt to provide any estimates here.

Network congestion occurs when one or more lines are operating at their rated limits. This condition may affect a large area of the system because the capacity of other lines may not be available without overloading the lines that are already at their limits. Congestion results in price separation throughout the region. Our model represents more than 11,000 lines in the MISO system. Of those, nine were fully loaded (i.e., at 100 percent of capacity) once we optimized power flow for the competitive-market case.[23] Table 3-6 lists the locations and nominal voltages for these nine lines.

---

[23] In addition to the fully loaded lines identified in Table 10, other overloaded lines were identified by the optimal power flow simulation; however, because of the system topology, these lines could not be relieved by the optimization program. These lines, called "Unenforceable Constraints," had to be relieved by hand, and are discussed in Section 5.

Table 3-6. Fully-loaded Lines in the Optimized MISO System

Max Nominal kV of Line	# Fully-loaded Lines	Location (Number of lines)
345	2	ALTE (2)
138	4	CIN, CONS, LGEE, CE-NIPS
69	3	AMRN (2), CIN

Enforcement of these line limits in the power-flow optimization causes the differences in the congestion components of LMPs throughout the system. However, it is important to note again that all the congestion is not introduced by the optimization; congestion exists in the system as it is currently dispatched in the state-estimator data. It is simply easier to identify and quantify with LMPs. It is also important to keep in mind that congestion is not inherently good or bad; the existence of congestion in an optimized centralized-dispatch case is an indication that the system is being fully utilized to optimize production.

The congestion revenues reported in this analysis were calculated by multiplying the flow across each line (not including losses) by the difference between the congestion components of the LMPs at the receiving and sending buses. This calculation was performed for every line that had both of its terminal buses within the MISO system; buses outside of MISO did not have LMPs, so congestion revenue could not be calculated. Both positive and negative congestion was observed in the system; these values were added together to obtain the net congestion reported below.

Net congestion revenue in the optimized MISO system was $227,717/h. The majority of this congestion revenue, $226,258/h, was within the boundaries of existing NERC control areas in the MISO footprint. Only 0.6 percent of total congestion revenue, $1,459/h, is at the seams between existing control areas in the MISO footprint. This is an interesting finding because it might be presumed that the introduction of centralized dispatch would result in greater congestion along the untested borders separating control areas. Our analysis indicates that this is not the case.

Figure 9 shows the geographic location of both intra-area and inter-area congestion. All intra-area congestion ranges from $15,000/h to -$15,000/h with the exception of Cinergy (CIN) and LG&E Energy (LGEE), which have $47,628/h and $151,635/h of congestion revenue, respectively. These areas are shown as slightly larger than the other control areas to indicate this difference. Congestion between control areas ranges from nearly $6,000 to around -$3,000/h on each line.

Table 3-7 and Table 3-8 list of all the congestion values.

To place the congestion revenues in perspective, consider that the value for total congestion revenues, $227,717/h is on the order of 20 percent of the value of the variable production costs of $1,113,157/h. At first glance, this may seem like a significant markup, but it is important to note that these congestion revenues are disbursed to those with financial transmission rights, which can mitigate financial burdens introduced by congestion.

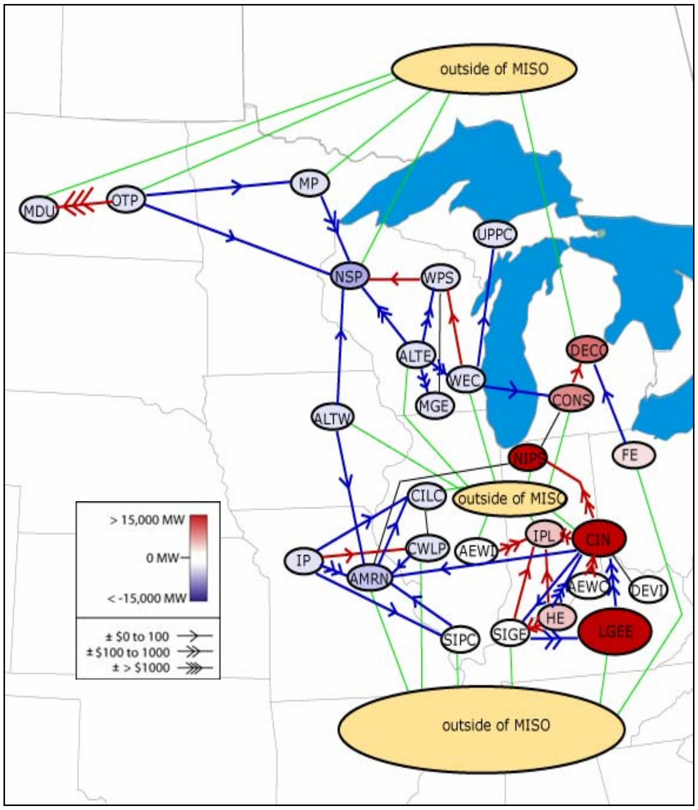


Figure 9. Congestion Revenue in Optimized MISO System

Table 3-7. Intra-Control-Area Congestion Revenue, July 7 OPF Case

Control Area	Congestion Revenue
Total	**$226,258/h**
LG&E Energy	$151,635
Cinergy Corp.	$47,628
Northern Indiana Public Service Co.	$14,256
Detroit Edison Company	$8,507
Consumers Energy Company	$7,183
Indianapolis Power & Light Co.	$3,797
Hoosier Energy Rural Electric Coop.	$3,373
First Energy	$1,793
Southern Indiana Gas & Electric	$897
Southern Illinois Power Coop.	$43
Allegheny Energy - Wheatland IPL	$0
Allegheny Energy - Wheatland CIN	$0
Duke Energy	$0
Upper Peninsula Power Co.	-$4
City WL&P-Springfield	-$78
Otter Tail Power Co.	-$208
Wisconsin Electric Power	-$254
Madison Gas & Electric Company	-$275
Central Illinois Light Co.	-$473
Montana-Dakota Utility Co.	-$473
Minnesota Power Co.	-$656
Wisconsin Public Service Coop.	-$792
Alliant West	-$1,123
Alliant East	-$1,333
Illinois Power	-$1,418
Ameren	-$1,649
Northern States Power Co.	-$4,118

Table 3-8. Inter-Control Area Congestion Revenue, July 7 OPF Case

Control Area	# interface lines	Congestion Revenue
Total	**937**	**$1,459/h**
OTP to MDU	4	$5,616
AEWC to CIN	2	$1,390
CIN to NIPS	4	$203
AEWI to IPL	1	$197
CIN to IPL	7	$145
HE to SIGE	5	$138
CONS to DECO	9	$97
SIGE to IPL	1	$76
WEC to WPS	23	$34
HE to IPL	1	$20
IP to CWLP	1	$4
WPS to NSP	1	$0
AMRN to NIPS	1	$0
CIN to DEVI	1	$0
CONS to NIPS	1	$0
CWLP to CILC	2	$0
WPS to MGE	1	$0
IP to SIPC	2	$0
SIPC to AMRN	2	-$3
CIN to SIGE	2	-$3
IP to CILC	7	-$7
WEC to CONS	2	-$8
OTP to NSP	2	-$9
CWLP to AMRN	2	-$14
ALTW to AMRN	8	-$17
WEC to UPPC	13	-$18
CIN to AMRN	2	-$30
ALTW to NSP	24	-$35
AMRN to CILC	1	-$38
FE to DECO	3	-$46
OTP to MP	10	-$98
ALTE to WPS	27	-$116
SIGE to LGEE	1	-$144
ALTE to MGE	20	-$219
IP to AMRN	47	-$267
ALTE to WEC	10	-$267
MP to NSP	8	-$420
ALTE to NSP	1	-$565
CIN to LGEE	6	-$1,079
HE to CIN	22	-$3,059

For a complete definition of all the control-area acronyms, please see Appendix B.

3.5 Observations of Negative LMPs, Negative Congestion, and Negative Marginal Profit

Typically, we would expect to pay (or receive) positive dollar amounts for energy, and we would also expect that market/engineering forces will promote energy flow from lower-cost areas to higher-cost areas. Although these expectations are consistent with what we note in the majority of our analysis, we also found several contrary occurrences. These included negative LMPs at some load buses, negative congestion revenue across some lines, and negative marginal operating profits for some generators. We describe these occurrences below and offer preliminary interpretations of the reasons for them.

A negative LMP indicates that a load is being paid to consume energy at a particular bus, on the margin, because increased consumption at that point would relieve congestion in another area and reduce system costs overall. Negative LMPs should encourage load to consume more, up to the point where the LMP equals the intrinsic value of electricity for that load. In the July 7 centralized-dispatch model, 176 MW of load distributed among 20 load buses, all in the Hoosier Energy Rural Electric Corp. (HE) and CIN control areas, had negative LMPs. We observe that this is a small number of negative prices in relation to the entire MISO system, which contains 6,418 load buses consuming 85,952 MW, and that the impact of negative or large positive LMPs may not be directly apparent to loads because retail rates only reflect average costs.

The OPF model also revealed negative congestion revenue on many lines. In general, negative congestion indicates that power is flowing from a high-cost area to a low-cost area, something that would not happen in the case of most commodities. This “reverse” flow of electricity results from a combination of system congestion and topology. In some cases power had to flow in a locally “uneconomic” way to meet all the load, respect line limits, and minimize production costs. Table 3-9 distinguishes between the lines with positive and negative congestion revenues.

Table 3-9. Positive and Negative Congestion Revenue revealed in OPF

Congestion Revenue	# Lines	Amount ($/MWh)
Positive	3,496	438,101
Negative	4,895	-210,384
Zero	1,390	0

Of the 1,026 generators in the MISO model, 150 were operating at a negative marginal profit after the optimization performed for this study. (It is impossible to tell whether any generators were running at a loss before the optimization because we do not have historical price information.) This result has at least two plausible explanations. The first is that these generators, which were “on” during the historic hour from which the data were taken, must run for reliability reasons, are required to do so by the system operator, and are compensated not through the traditional pricing scheme but in some other way, such as uplift charges. Another possible explanation is that our optimization software cannot make unit commitment decisions, i.e., turn on a generator that was off and vice versa. In reality, negative operating profits, if large, would lead operators to shut down. At the same time, profit opportunities under LMPs may be so large that generators that were originally off-line might be dispatched.

4. Sensitivity Analysis

The findings from our initial analysis are based on examination of the change in dispatch for a single hour during the summer season for the current MISO members. In this section, we analyze two sensitivities to the basic assumptions of our initial analysis: First, we examine how our findings change based a different composition of MISO members, and, second, we examine how our findings change based on a different set of loads and generators, taken from another season.

4.1 Sensitivity to MISO Membership

The results in Section 3 are based on the roster of expected MISO members as of March 2004. Competition, if perfect, would minimize the aggregate costs of production by these members by changing the dispatch of their combined assets. The larger the membership, the greater the potential for reducing costs, assuming that the market is competitive so that these members are able to trade freely. We explored the degree to which the composition of MISO membership affects our results by reexamining the comparison of decentralized versus centralized (competitive-market) dispatch, assuming a larger number of MISO members taken from 2003.

When the current roster of 27 MISO members (referred to as “2004 Members”) is replaced by the 37 members that MISO anticipated in June 2003, (referred to as “2003 Members) the results of our analysis change significantly. (Table 4-1 lists the two rosters of members). Characteristics of the optimized area with the 2003 Member list are shown in Table 4-2 and 4-3. Compared to the results for the 2004 Members, the number of all electrical components within the area to be optimized increased when based on 2003 Members, as does the load being served and the generation available to meet that load.

However, the increases were small because the areas represented by the 2004 Members are more electrically contiguous than are the areas represented by the 2003 Members. Hence, centralized dispatch based on the 2003 Members does not allow completely free trade among all MISO members because interchanges between MISO and non-MISO areas are restricted to the historical interchange value observed in the actual dispatch (which was not based on centralized dispatch). This restriction was also employed in our analysis relying on 2004 Members.

Table 4-1. NERC Control Areas that are in MISO Member Lists for 2003 and 2004

Control Areas in both 2003 & 2004 MISO Member Lists	Control Areas in 2003 MISO Member List only	Control Areas in 2004 MISO Member List only
Allegheny Energy - Wheatland IPL	Dairyland Power Cooperative	Ameren
Allegheny Energy - Wheatland CIN	Great River Energy (Central)	Illinois Power
Alliant East	Lincoln Electric System	Northern Indiana Public Service Co.
Alliant West	MidAmerican Energy	
Central Illinois Light Co.	Manitoba Hydro Electric Board	
Cinergy Corp.	Missouri Public Service Co.	
Consumers Energy Company	Muscatine Power & Water	
City WL&P-Springfield	Nebraska Public Power District	
Detroit Edison Company	Omaha Public Power District	
Duke Energy	Southern Minnesota Muni. Power	
First Energy	Saskatchewan Power Corporation	
Hoosier Energy Rural Electric Coop.	WAPA - Upper Great Plains East	
Indianapolis Power & Light Co.	West Plains Energy	
LG&E Energy		
Montana-Dakota Utility Co.		
Madison Gas & Electric Company		
Minnesota Power Co.		
Northern States Power Co.		
Otter Tail Power Co.		
Southern Indiana Gas & Electric		
Southern Illinois Power Coop.		
Upper Peninsula Power Co.		
Wisconsin Electric Power		
Wisconsin Public Service Coop.		

Table 4-2. Comparison of Electrical Components and Operations for 2003 vs. 2004 MISO Members

System Characteristics	2003 MISO Members	2004 MISO Members
Control Areas	37	27
Electrical Configuration		
Buses	12,118	8,926
Lines/Transformers	14,656	11,434
Generators	1,280	1,026
Capacity	132,027 MW	123,005 MW
Operations 7/7/2003 (base case)		
Generation	83,468 MWh	80,108 MWh
Load	88,173 MWh	85,953 MWh
Net Exports	-7,061 MWh	-7,760 MWh

Table 4-3. Generation Capacity within MISO Footprint for 2003 vs. 2004 MISO Members

Capacity	2003 MISO Members	2004 MISO Members
Total (MW)	132,027	123.005
On line (MW)	102,667	97,624
% of total	78%	79%
Fixed Output (MW)	9,979	1,964
(% of on line)	10%	2%
(% of load)	11%	2%
Redispatchable (MW)	92,688	95,300
(% of on-line)	90%	98%
(% of load)	105%	111%

4.1.1 Generation Dispatch

The total amount of generation capacity and output within the control areas for the list of 2003 Members is greater than capacity and output for the list of 2004 Members. The percent of fixed generation output is also greater for the 2003 Members, which means less load can be met with a different, or cheaper, set of generation. As a result of relying on centralized dispatch, 21 control areas increased generation output, and 12 control areas decreased output for the list of 2003 Members; in contrast, 14 control areas increased generation output, and 11 control areas decreased output for the list of 2004 Members. The changes in control area generation for both lists of members are shown in Figure 10. The changes in control-area generation for the 2004 Members are smaller and, in some cases contradictory to those for the 2003 Members, except for the Indiana, Kentucky, Ohio, Michigan region where the pattern of generation change appears to be roughly the same.

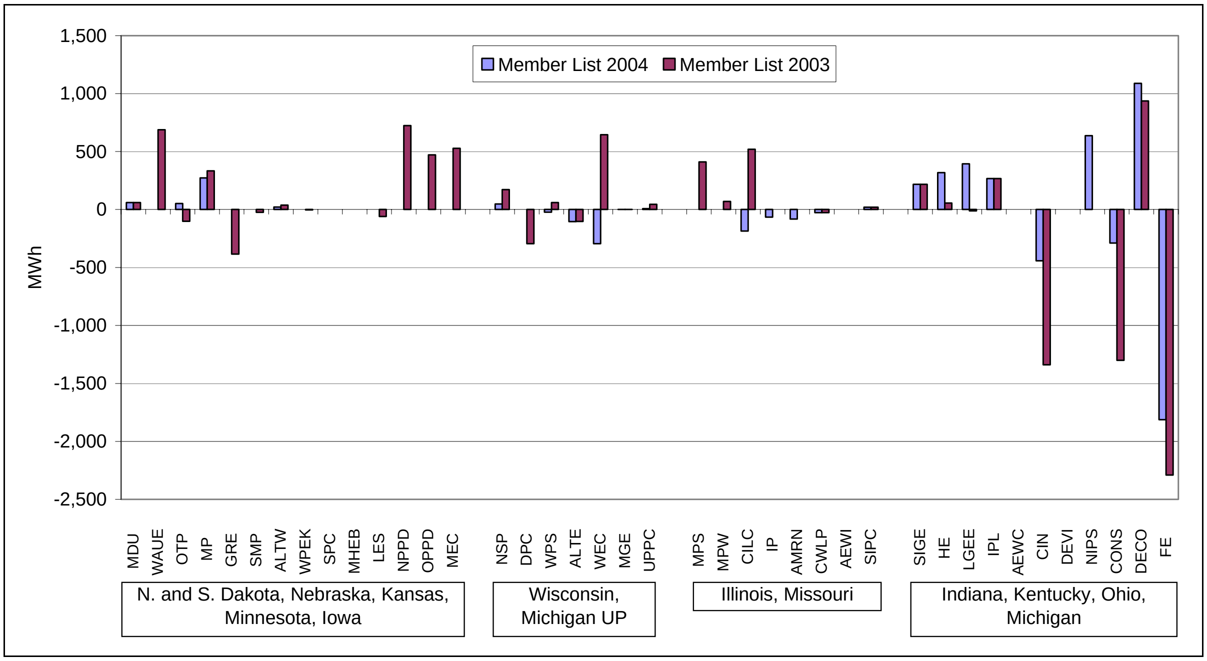


Figure 10. Comparison of Generation Change from Centralized Dispatch for MISO 2003 Members vs. 2004 Members

Table 4-4 and Table 4-5 list the control areas with largest and smallest changes in generation between the base case and optimally dispatched case for both 2003 Members and 2004 Members. The table shows both the change in dispatch for both control-area lists to give an idea of how different the changes were for the different memberships; in some cases, these differences were substantial. For example, using the 2003 Members, Wisconsin Electric Power Company (WEC) experienced a positive change in generation of 646 MW, but, when using 2004 Members, WEC experienced a negative change of 294 MW. In cases where control areas only appear in one list of members, no comparison value is reported.

Table 4-4. Control Area with Greatest Positive and Negative Change in Generation Dispatch, 2003 MISO Members

Control Area	Generation Dispatch Change based on 2003 MISO Members	Generation Dispatch Change based on 2004 MISO Members
Greatest Positive Generation Dispatch Change		
Detroit Edison Company	936	1,088
Nebraska Public Power District	724	-
WAPA - Upper Great Plains East	689	-
Wisconsin Electric Power	646	-294
Greatest Negative Generation Dispatch Change		
Great River Energy	-384	-
Consumers Energy Company	-1,302	-289
Cinergy	-1,339	-442
First Energy	-2,290	-1,813

Table 4-5. Control Areas with Highest and Lowest Change in Generation Dispatch, 2004 MISO Members

Control Area	Generation Dispatch Change based on MISO 2004 Members	Generation Dispatch Change based on MISO 2003 Members
Greatest Positive Generation Dispatch Change		
Detroit Edison Company	1,088	936
Northern Indiana Public Service Co.	637	-
LG&E Energy	394	-11
Hoosier Energy Rural Electric Coop.	318	56
Greatest Negative Generation Dispatch Change		
Consumers Energy Company	-289	-1,302
Wisconsin Electric Power	-294	646
Cinergy	-442	-1,339
First Energy	-1,813	-2,290

4.1.2 System Cost

The difference in variable system costs between the base and OPF cases for the 2003 Members is nearly $442,000/h, roughly a $110,000/h larger decrease in variable system cost than for the 2004 Members. However, because the initial variable system cost for the 2003 Members is larger than that for the 2004 Members, the percent change between the base case and the OPF case is almost the same (23 percent) for both member lists. These observations are summarized in Table 4-6.

Table 4-6. Comparison of Variable Operating Costs, 2003 MISO Members vs. 2004 MISO Members

Costs	2003 MISO Members	2004 MISO Members
Base-Case Variable System Cost	$1,813,391	$1,440,574
OPF Variable System Cost	$1,371,862	$1,113,157
Total Change in Variable System Cost	$441,529	$327,417
% Change in Variable System Cost	24%	23%

4.1.3 LMPs

LMPs both increased and decreased for the 2003 Members, compared to the values calculated for the 2004 Members (see Figure 11). The highest average LMPs for the 2003 Members are concentrated in Wisconsin, as opposed to the results of the previous analysis in which high LMPs were concentrated in Indiana, Kentucky, Ohio, and Michigan.

Notice that the Alliant East control area has the highest average LMPs for the 2003 Members, but the lowest average LMP for the 2004 Members. This difference is caused by congestion in this area changing dramatically between the two cases, a result of the change in control over the electricity network.

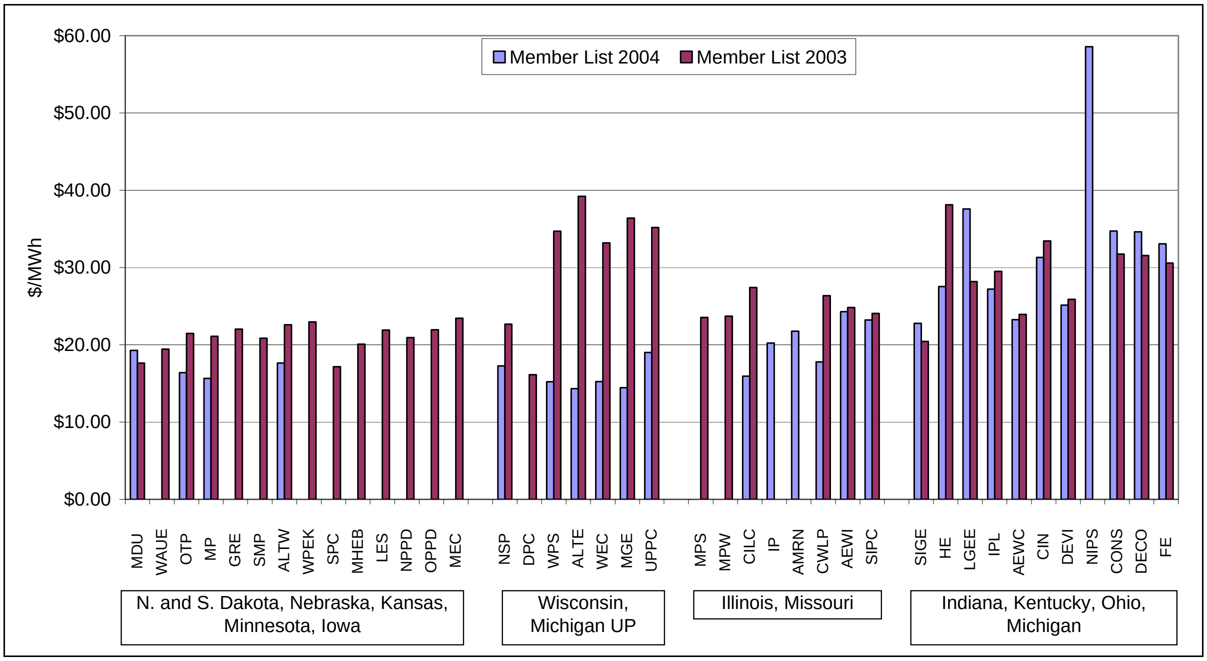


Figure 11. Comparison of LMPs from Centralized Dispatch, 2003 vs. 2004 MISO Members

In fact, there appears to be little similarity between the average LMPs calculated in the 2003 and 2004 membership cases, especially at the low and high ends of the range. Table 4-7 and Table 4-8 list the highest and lowest average LMPs from both the OPF simulation for 2003 Members and 2004 Members, as well as the "rank" from both cases. The rank identifies the magnitude of average LMP compared to all other control areas in that particular run, with 1 being the highest average LMP, 27 the lowest average LMP in the 2004 Members case, and 37 the lowest average LMP in the 2003 Members case. For instance, for 2003 Members, Alliant East had the highest average LMP and is therefore ranked first, as "1"; under 2004 Members, Alliant East has the lowest LMP and is ranked last, as "27." When a control area is not present in both cases, a rank is not given.

Table 4-7. Highest and Lowest Average Control-Area LMPs, 2003 MISO Members

Control Area	Average LMP using 2003 MISO Members	Ranking using 2003 MISO Members (out of 37)	Ranking using 2004 MISO Members (out of 27)
Highest Average LMPs			
Alliant East	$39	1	27
Hoosier Energy Rural Electric Coop.	$38	2	7
Madison Gas & Electric	$36	3	26
Upper Peninsula Power Co.	$35	4	17
Lowest Average LMPs			
WAPA – Upper Great Plains East	$19	34	-
Montana Dakota Utilities	$18	35	16
Saskatchewan Power Corporation	$17	36	-
Dairyland Power Cooperative	$16	37	-

Table 4-8. Highest and Lowest Average Control-Area LMPs, 2004 MISO Members

Control Area	Average LMP using 2004 MISO Members	Ranking using 2004 MISO Members (out of 27)	Ranking using 2003 MISO Members (out of 37)
Highest Average LMPs			
Northern Indiana Public Service Company	$59	1	-
LG&E Energy	$38	2	12
Consumer Energy Company	$35	3	8
Detroit Edison Company	$35	4	9
Lowest Average LMPs			
Wisconsin Electric Power	$15	24	7
Wisconsin Public Service Coop.	$15	25	5
Madison Gas & Electric Company	$14	26	3
Alliant East	$14	27	1

4.1.4 Congestion

When using the different member lists, the value of congestion revenue changes in every control area, but congestion still occurs mainly within, rather than between, control areas. (See Table 4-9.) The total congestion revenue for the 2003 Members was $100,996/h, of which $97,127/h was intra-area. This is less than half of the congestion revenue for the 2004 Members.

This dramatic decrease in congestion revenue is attributable to one control area, LGEE. The value of congestion revenue within LGEE is greater than the difference between the congestion revenues in the two member-list cases.

Table 4-9. Comparison of Congestion Revenue, 2003 vs. 2004 MISO Members

Revenue	2003 MISO Members	2004 MISO Members
Total Congestion Revenue	$100,996	$227,717
Inter-Area Congestion Revenue	$97,127	$226,258
Intra-Area Congestion Revenue	$3,869	$1,459
% Total Congestion Revenue occurring within areas	96%	99%

Control areas with the largest positive and negative congestion revenues are listed below in Table 4-10 and Table 4-11, along with the amount of congestion revenue in the 2003 and 2004 cases. Note in particular the Alliant East area: the congestion revenue pattern for that control area in the two membership cases mirrors the differences seen in LMPs. For the 2003 Members, Alliant East's LMP and congestion revenues are among the highest in the system; for the 2004 Members, Alliant East's average LMP is the lowest and congestion revenue is negative. A comparison of all control areas is shown in Figure 12.

Table 4-10. Greatest Positive and Negative Control Area Congestion Revenue, MISO 2003 Members

Control Area	Congestion Revenue using 2003 MISO Members	Congestion Revenue using 2004 MISO Members
Greatest Positive Congestion Revenue		
Cinergy Corp.	$50,909	$47,628
Alliant East	$18,107	-$1,333
Hoosier Energy Rural Electric Coop.	$9,968	$3,373
Indianapolis Power & Light Co.	$7,214	$3,797
Greatest Negative Congestion Revenue		
WAPA – Upper Great Plains East	-$877	-
Manitoba Hydro Electric Board	-$1,004	-
Northern States Power Co.	-$2,228	-$4,118
Alliant West	-$5,136	-$1,123

Table 4-11. Greatest Positive and Negative Control Area Congestion Revenue, MISO 2004 Members

Control Area	Congestion Revenue using 2004 MISO Members	Congestion Revenue using 2003 MISO Members
Greatest Positive Congestion Revenue		
LG&E Energy	$151,635	$6,113
Cinergy Corp.	$47,628	$50,909
Northern Indiana Public Service Company	$14,256	-
Detroit Edison Company	$8,507	$3,829
Greatest Negative Congestion Revenue		
Alliant East	-$1,333	$18,107
Illinois Power	-$1,418	-
Ameren	-$1,649	-
Northern States Power Co.	-$4,118	-$2,228

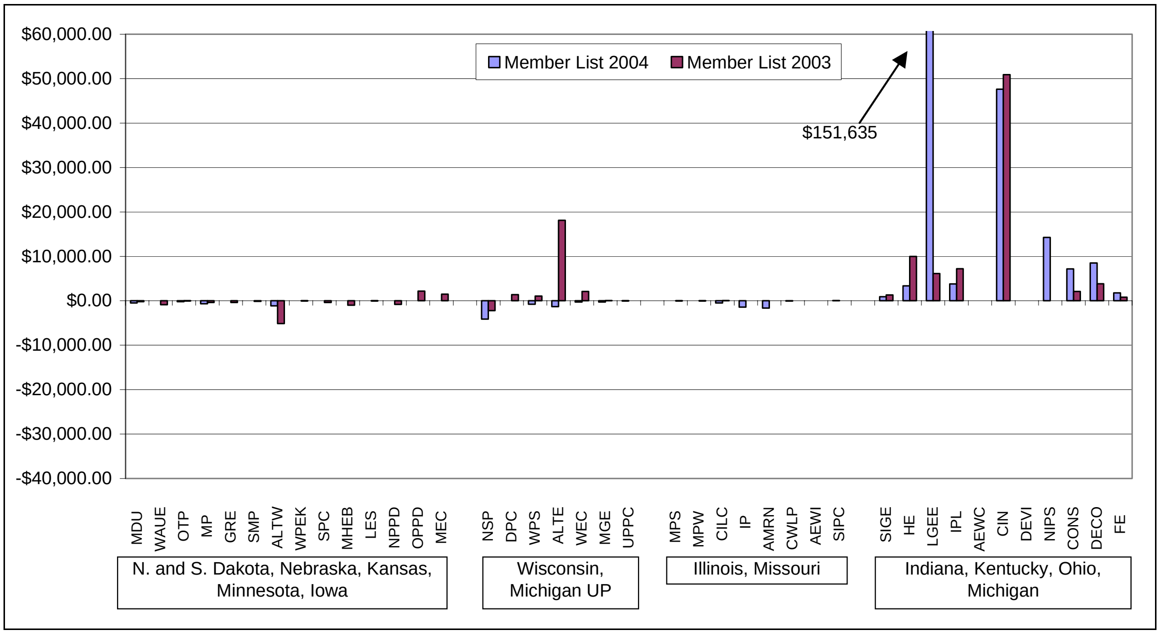


Figure 12. Comparison of Intra-area Congestion Revenue under Centralized Dispatch, MISO 2003 vs. 2004 Members

One reason for the disparity between generation, flows, system cost, LMPs and congestion for the 2003 Members versus the 2004 Members is that the load being met and the generation available for dispatch are different in the two cases. This necessarily leads to different solutions for the centralized-dispatch case.

Another reason for the difference in results is that controls areas for the 2004 Members form an electrically contiguous part of the grid in which all members can trade freely whereas control areas using the 2003 Members formed five separate electrically contiguous areas. In the 2003 configuration, members within each distinct area could trade among themselves, but trade among the five areas was restricted to the historic trade defined in the state-estimator snapshot, which restricted how generators could be dispatched to meet load in our model.

4.2 Sensitivity to Season, Loads, and Generation Availability

As discussed in Section 2, the choice of reference data can be critical to results. To assess how using different reference data might change our results, we repeated our analysis using loads and generation data from February 18, 2004 instead of July 7, 2003. The February 18, 2004 case is the most recent state-estimator solution provided by MISO for our study. The system model used in the February case is more detailed than is the model MISO provided for the July case, especially for the regions outside the MISO footprint. Table 4-12 compares the electrical components represented within the MISO footprint and the operating conditions for the two cases.

To allow for a direct comparison of results, the February case uses several elements from the July case. Although we rely on loads and generation from February, all cost analysis is performed using data from the July case. We also base the redispatch on the 2004 list of MISO members. These conventions allow us to focus more directly on how dispatch, LMPs, and congestion compare in a qualitative sense, both between actual and centralized dispatch, and between July and February loads and generation availability. Table 4-13 compares the generation capacity and portion of generation available for redispatch. Roughly four percent of MISO load is met with fixed generation from within MISO, and imports serve roughly an additional nine percent. The remaining demands and losses are met through optimal economic use (i.e., centralized dispatch) of generators with in the MISO region.

It is worth noting that the amount of operating reserve margin (the excess of on-line capacity over demand) in Table 4-13 is significantly greater for the February case than for the July case even though demand is less in the February case. This difference in the amount of generation on line (and, for our purposes, available for centralized redispatch) depends on many factors including the different demand profiles, demand relative to peak for that day, contractual obligations (although, in net, the imports do not differ greatly in the two cases), and security concerns (which may have been modified since the August 14, 2004 blackout).

Table 4-12. Comparison of Electrical Components and Operations on July 7, 2003 vs. February 18, 2004

System Characteristics	July 2003	February 2004
Control Areas	27	27
Electrical Configuration		
Buses	8,926	9,154
Lines/Transformers	11,434	12,209
Generators	1,026	1,052
Capacity	123,005 MW	128,134 MW
Operations (base cases)		
Generation	89,108 MWh	65,458 MWh
Load	85,953 MWh	70,135 MWh
Net Exports	-7,760 MWh	-6,422 MWh

Table 4-13. Generation Capacity within MISO Footprint on July 7, 2003 vs. February 18, 2004

Capacity	July 2003	February 2004
Total (MW)	123,005	128,134
On line (MW)	97,624	90,598[24]
(% of total)	79%	86%
Fixed Output (MW)	1,964	2,796[25]
(% of on-line)	2%	2%
(% of load)	2%	4%
Redispatchable (MW)	95,300	76,415
(% of on-line)	98%	68%
(% of load)	111%	109%

4.2.1 Generator Dispatch

In Figure 13 we compare the changes in centralized OPF dispatch by control area from the historical base cases for both the July and February cases. The control areas with greatest increases and decreases for each case are listed in Table 4-14 and Table 4-15. The lists of greatest increases do not overlap significantly; none of the top four control areas are common to both lists. The lists of greatest decreases share two control areas among the top four: First Energy and Consumers Energy Company.

Assuming these two snapshots are representative of changes in seasonal conditions, we have to conclude that changes in patterns of centralized dispatch can vary significantly by season.

[24] The total generation capacity listed as on line in the data is 103,147 MW, but 12,550 MW are listed as producing 0 MW and 0 Mvars. We treat these as off line.

[25] The February data used different bus numbers and, in some cases, different bus names than the July 2003 case. It was not possible to match all generators between the cases. Consequently, more of the generation is fixed in the February case than in the July case, but this fixed generation still only serves a small percentage of the total load.

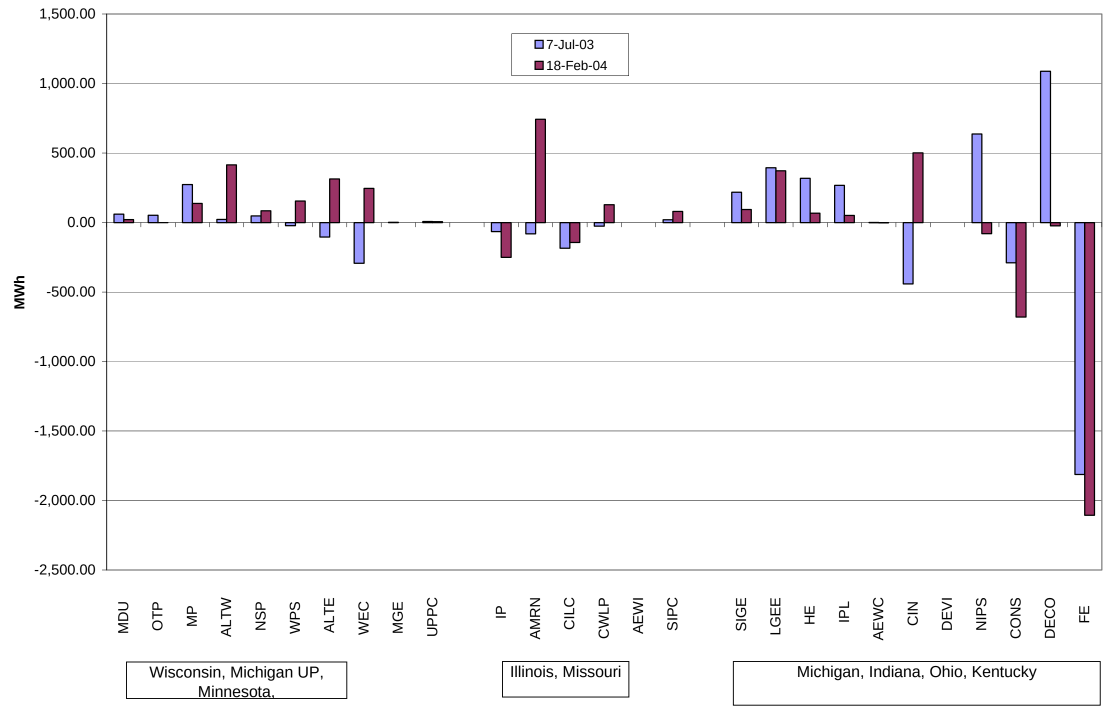


Figure 13. Comparison of Generation Change under Centralized Dispatch for the July 7, 2003 and February 18, 2004 Cases

Table 4-14. Control Areas with Greatest and Least Change in Generation Dispatch in the February 2004 Case Compared with the July 2003 Case

Control Area	Generation Dispatch Change in February 2004 case (MW)	Generation Dispatch Change in July 2003 case (MW)
Greatest Generation Dispatch Change		
Ameren	743	-82
Cinergy	501	-442
Alliant West	415	22
LG&E Energy	372	394
Least Generation Dispatch Change		
First Energy	-2,106	-1,813
Consumers Energy Company	-679	-289
Illinois Power	-251	-65
Central Illinois Light Company	-144	-185

Table 4-15. Control Areas with Greatest and Least Change in Generation Dispatch in the July 2003 Case, Compared with the February 2004 Case

Control Area	Generation Dispatch Change in 2004 Case	Generation Dispatch Change 2003 Case
Greatest Generation Dispatch Change		
Detroit Edison Company	1,088	-24
Northern Indiana Public Service Co.	637	-80
LG&E Energy	394	372
Hoosier Energy Rural Electric Coop.	318	67
Least Generation Dispatch Change		
First Energy	-1,813	-2,106
Cinergy	-442	501
Wisconsin Electric Power	-294	245
Consumers Energy Company	-289	-679

4.2.2 System Cost

A comparison of variable operating costs for the two cases is shown in Table 4-16. The improvement in variable system costs offered by centralized dispatch is significant in both cases: a 23-percent reduction for the July case, and an 18-percent reduction for the February case. It is mildly surprising that the variable system costs under centralized dispatch are lower for the higher demands in the July case than for the lower demands in the February case. This may be related to the differences in unit commitment we noted above for the February case, which result in a large operating reserve for the February case.

Table 4-16. Comparison of Variable Operating Costs, July 2003 Case and February 2004 Case

Cost	July 2003	February 2004
Base Case Variable System Cost	$1,440,574	$1,381,963
OPF Variable System Cost	$1,113,157	$1,127,514
Total Change in Variable System Cost	$327,417	$254,449
% Change in Variable System Cost	23%	18%

4.2.3 LMPs

The LMPs are shown by control area for both cases in Figure 14. The LMPs for the two cases share the feature that the higher prices occur in the eastern portion of the network. The highest and lowest LMPs, listed in Table 4-17 and Table 18, are not identical, but they are qualitatively similar. The price difference between regions, however, is markedly different. In the July case, the price differential between areas in the eastern and western portions of the MISO system is more pronounced than in the February case. Intuitively, this might suggest that the July case is more congested, which is consistent with the higher load and much lower operating reserve margin for that case. The greater congestion is confirmed in the next section**.**

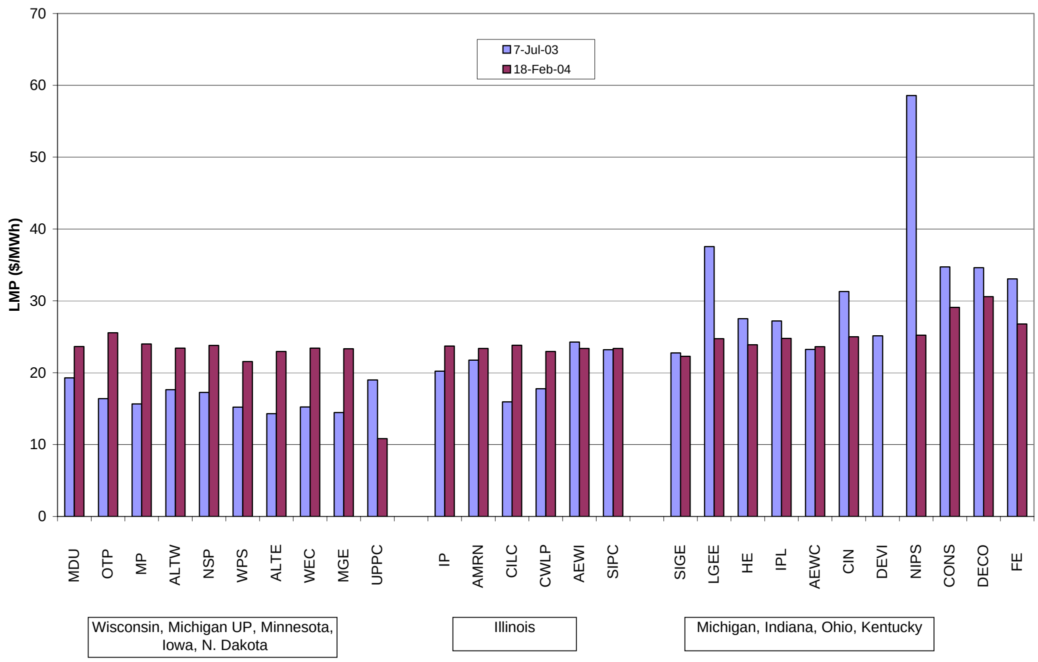


Figure 14. Comparison of LMPs for July 7, 2003 OPF Case and February 18, 2004 OPF Case

Table 4-17. Highest and Lowest Average Control-Area LMPs, February 2004 Case compared with July 2003 Ranking

Control Area	Average LMP in February 2004 Case	Ranking in February 2004 Case (out of 27)	Ranking in July 2003 Case (out of 27)
Highest Average LMPs			
Detroit Edison Company	$31	1	4
Consumers Energy Company	$29	2	3
First Energy	$27	3	5
Otter Tail Power Company	$26	4	21
Lowest Average LMPs			
Alliant East	$23	23	27
Southern Indiana Gas and Electric	$22	24	13
Wisconsin Public Service	$22	25	25
Upper Peninsula Power Co.	$11	26	17

Table 4-18. Highest and Lowest Average Control Area LMPs, July 2003 Case, With Comparison to February 2004 ranking

Control Area	Average LMP in July 2003 Case	Ranking in July 2003 Case (out of 27)	Ranking in February 2004 Case (out of 27)
Highest Average LMPs			
Northern Indiana Public Service Company	$59	1	5
LG&E Energy	$38	2	8
Consumer Energy Company	$35	3	2
Detroit Edison Company	$35	4	1
Lowest Average LMPs			
Wisconsin Electric Power	$15	24	23
Wisconsin Public Service Coop.	$15	25	21
Madison Gas & Electric Company	$14	26	25
Alliant East	$14	27	17

4.2.4 Congestion

Table 4-19 summarizes the congestion revenues for the two cases. We find that the congestion revenues are significantly higher in the July case, which is consistent with the higher loading and lower reserve margin for that case. In both cases, intra-area congestion revenue is greater than inter-area congestion revenue.

Figure 15 compares intra-area congestion revenues by control area. Most of the congestion occurs I the estern portion of the network in both cases. Table 4-20 and Table 4-21 list the extreme values for intra-area congestion revenues for each case. Because the total congestion revenues differ by an order of magnitude, relative rankings in each case are compared. The rank orderings are not exactly the same in the 2003 and 2004 cases, but they are qualitatively similar for the groupings in the east.

Table 4-19. Comparison of Congestion Revenue, July 2003 Case and February 2004 Case

Revenue	July 2003	February 2004
Total Congestion Revenue	$227,717	$24,256
Intra-Area Congestion Revenue	$226,258	$25,855
Inter-Area Congestion Revenue	$1,459	-$1,599
% Total Congestion Revenue occurring within areas	99%	107%[26]

[26] The negative inter-area congestion means that the intra-area congestion has a larger value than the total congestion. The important observation is that the total congestion is dominated by intra-area congestion.

Table 4-20. Greatest Positive and Negative Control-Area Congestion Revenue, February 2004 Case Compared with July 2003 Case

Control Area	Congestion Revenue in February 2004 Case	Ranking in February 2004 Case	Ranking in July 2003 Case
Greatest Positive Congestion Revenue			
Detroit Edison	$23,691	1	4
Consumer Energy Company	$3,541	2	5
Ameren	$1,318	3	26
Southern Indiana Gas&Electric	$759	4	9
Greatest Negative Congestion Revenue			
Otter Tail Power Co.	-$220	24	16
Alliant East	-$466	25	24
Northern States Power	-$735	26	27
Wisconsin Electric Power	-$2,770	27	17

Table 4-21. Greatest Positive and Negative Control-Area Congestion Revenue, July 2003 Base Case Compared with February 2004 Case

Control Area	Congestion Revenue in July 2003 Case	Ranking in July 2003 Case	Ranking in February 2004 Case
Greatest Positive Congestion Revenue			
LG&E Energy	$151,635	1	8
Cinergy Corp.	$47,628	2	7
Northern Indiana Public Service Company	$14,256	3	6
Detroit Edison Company	$8,507	4	1
Greatest Negative Congestion Revenue			
Northern States Power Co.	-$4,118	24	26
Ameren	-$1,649	25	3
Illinois Power	-$1,418	26	9
Alliant East	-$1,333	27	25

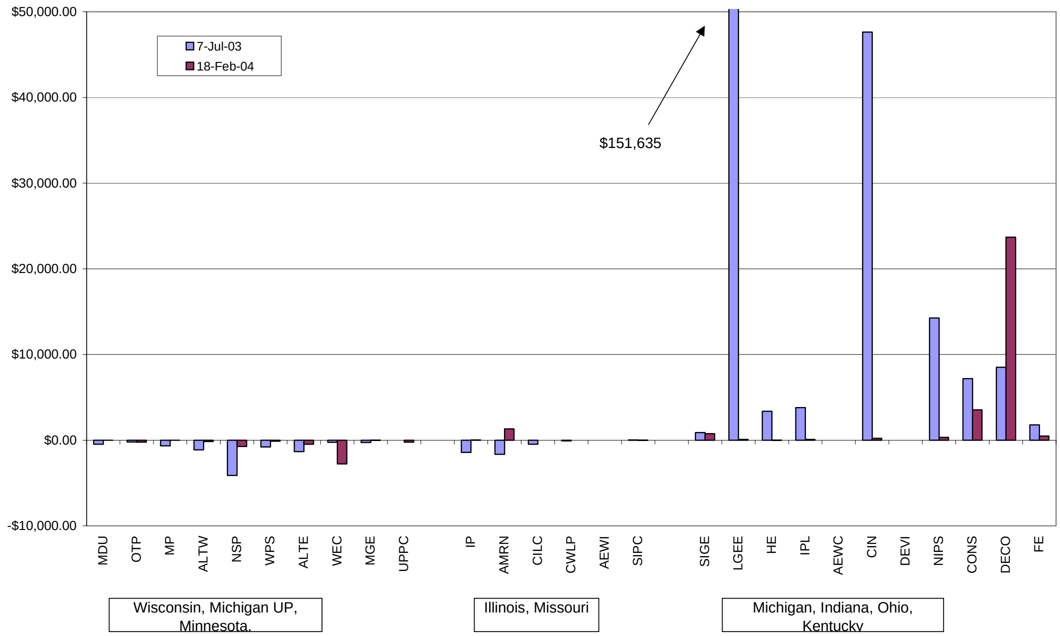


Figure 15. Comparison of Intra-area Congestion Revenue from OPF Analysis with July 7, 2003 Case and February 18, 2004 Case

5. Caveats and Directions for Future Research

The system models provided by MISO and the cost data provided by EIA help ensure that the overall patterns and trends in our findings are significant. We believe that our estimates are representative of the prices and dispatch changes that may unfold in a competitive MISO market when it opens in 2005. Nonetheless, we have had to make simplifying assumptions, and data are never perfect. In this section, we review some of the most important factors that could qualitatively change our findings and discuss additional analysis that would help us better understand the impacts of these factors.

Overall, we believe that, with one important exception, the possible biases introduced by inaccuracies in the model, data, and approach used in this study would tend to overestimate costs. Because the costs calculated in this report are not excessive, these biases are not large. The most significant of bias may be the assumption of fixed unit commitment. If a security-constrained optimal dispatch simulation with unit commitment were run for the MISO region as a whole, it would likely change the number and location of units dispatched relative to our results. Our study allowed generators to change their output but held fixed the list of generators on line and available to serve load. In our results, we note a few generators operating at their minimum output at locations where the LMP is below their marginal costs; these units would not be selected unless they are must-run for reliability, in which case they would be compensated in some other way.

A similar seams issue is related to the trade between MISO and regions outside MISO. We assume a historic level of trade as noted in the state estimator solution. It is not unreasonable to expect that the pattern of trade will be affected by market operation. Generators in regions tending to lower prices within MISO may find exporting opportunities outside MISO, and regions tending to increased prices may seek additional importing opportunities from outside MISO. By fixing the level of out-of-market trade to the historical level, we do not capture qualitative changes that might occur. Nevertheless, these seams issues are difficult to model and anticipate changes, and it is not clear how our assumptions bias our results, if at all.

In addition to trade across seams, internal bilateral trading within the MISO will affect the market. In this analysis we assume that most energy is available through a market, except for the net imports from outside ISO and the energy from generators without cost data. In practice we may expect a significant portion of energy will be acquired through bilateral contracts and a smaller portion will be purchased through the market. Since we assume competitive behavior, this assumption does not bias our results. In practice, however, concern should be given to a system in which all energy is traded in the market.

The important exception to the generalization that any biases in our study would overestimate costs is the assumption that the MISO wholesale electricity market will be fully competitive. We did not examine the possible effects of generators bidding above their production costs as an exercise of the market power that might be possible because of load conditions, the location of generation facilities, and/or congestion on existing pathways.

In addition, we have observed inaccuracies in the system models supplied by MISO. In particular, the solution of the state estimator shows lines operating above their rated capacity.

We expect that the system is operating in a secure manner, which leads us to believe that the line limits are erroneous. We have asked MISO to review this issue so that we can understand the impact it might have on our results. MISO reports significant modifications to the state estimator model since July 2003, and it has initiated a series of modeling workshops in which stakeholders are able to provide feedback to improve the model.

In the remainder of this section, we discuss these and other issues that might influence our findings:

Two load and generation configurations studied. A few snapshots cannot provide comprehensive economic results over a long time period. Our analyses provide representative results at select times and are intended to identify peculiarities, if any, in system dispatch, prices, and congestion. They are not intended to be used for any long-term economic study.

Unit commitment was not allowed to change under centralized dispatch. Those units on line for our analysis were committed at the time of the state-estimator snapshots provided for our study. Using actual unit commitment assures that the system is in a secure state, i.e., that there was enough capacity on line and correctly located to satisfy reliability criteria. Using these data eliminates the need for us to perform a security-constrained economic dispatch. If, however, a centralized security-constrained unit commitment and dispatch were performed, we expect that it would lower costs relative those found in our study. Our method is biased toward overestimating costs.

We did not have (or could not assign) complete cost information for all generation within the MISO footprint. We have EIA full-load heat-rate and fuel-cost data for approximately 98 percent of on-line generation (representing 77 percent of total capacity, and 50 percent of generators). Using full-load heat rates introduces an unknown bias. Qualitatively, this should not significantly affect our dispatch results because the optimal dispatch tends to use the entire capacity of the least-expensive plants. More accurate heat-rate data might shift prices up or down on the marginal, price-setting units that are not necessarily operating at full capacity. We do not expect this to have a large effect on prices or congestion revenues, moreover, it should not introduce any geographical biases.

We also were not able to match the names used to identify generators in the state-estimator solution provided by MISO to the names used to identify generators in the EIA production-cost files. If, however, we could align these data, the costs under centralized dispatch would decrease. Optimization through centralized dispatch of a larger number of units would only improve the model’s solution. This uncertainty adds an upward (probably small) bias in our results.

We assumed that no participant had or would unfairly exploit market power to raise prices above actual production costs. The assumption of a competitive market needs to be explored in future research. If the market is not competitive and generators are able to bid above their production costs and set the market clearing price, then our results will tend to over-state the benefits of centralized dispatch.

We found unenforced constraints in the optimal power-flow solution. Data irregularities were most noticeable in line-capacity limits. In all of the state-estimator solutions we examined, we noticed power flows exceeding stated limits. Our OPF attempts to enforce the limits but is not always able to do so, resulting in so-called “unenforceable constraints.” These limits are clearly erroneous because MISO is operating securely, so we relieved them manually by increasing the stated capacity.

MISO is continually updating its model, and we have informed them of these data issues. The model is very large, and it is possible that similar erroneous limits are being enforced by our OPF. This would bias our results upward.

We enforced all transmission line capacity constraints in the MISO footprint. Our approach may be overly restrictive if MISO operation only considers a subject of transmission line for which flows are constrained by placing overall limits on flowgates. The bias of a more restrictive analysis tends to increase costs and prices, but the distribution is not known.

Congestion costs between MISO and non-MISO areas are not quantified. One of the benefits of LMPs is that they allow easy identification and quantification of congestion charges. The costs of congestion between MISO and the rest of the system model are not easily calculated.

In view of the issues listed above, we recommend future studies that take include the following enhancements:

- Additional state-estimator snapshots;
- More sensitivity studies to address membership, generator costs, and transmission line outages; and
- Simulations that consider bilateral transactions.

The additional state-estimator snapshots will give a more comprehensive view of operating conditions over the course of a year than is possible with the single snapshot that we used. To add to that baseline, the sensitivity studies will identify critical assumptions that might affect the market. We have already seen that the combined assumptions of membership and bilateral trade can make a difference in the results. To address bilateral-trade models, we could consider the historical model used here as well as a representation akin to a hurdle-rate model.

Most importantly, research needs to identify instances in which market power may be exploited. This study assumed that the market is competitive, which may not be the case for all operating characteristics. Developing methods for determining market-power potential is an important research issue. Current market monitoring and mitigation for Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) rely on detecting variation from historical offers and resulting dispatch and prices. These variations are hard to simulate in an ad hoc manner. We propose to use sensitivity studies to identify participants or groups of participants with the ability to increase profits through offers and then assess the extent to which this ability may be exploited.

Appendix A. Comparison of Our Findings to Those in Related Reports

Two recent reports that are relevant to our work are the April 30, 2003 DOE *Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Design*, (DOE/S-0138) and the March 26, 2004 MISO report *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*. We summarize the basics of each report below. Most of the results of our study are not directly comparable to results in these reports because we do not have the same information about market costs and financial transmission rights (FTR) allocations. Our work complements these studies by providing information on possible congestion patterns and changes in dispatch and variable operating costs.

DOE Report

The DOE report attempts to quantify the benefits of adopting FERC's Standard Market Design (SMD) Proposal. DOE compares energy prices, expected retail costs, and increased transmission usage under April 2003 operating and regulatory conditions and SMD operating conditions. The Policy Office Electricity Modeling System (POEMS) was used for pricing and long-term forecasts. For transmission usage, a detailed transmission model and the General Electric Multi-Area Production Simulation (GE-MAPS) tool was used. Nationwide, the results suggest that net consumer savings from implementation of the SMD would range from $700M/yr (long-term) and $1B/yr (short term). These amounts are slightly larger than the increased costs of establishing and operating RTOs, which estimated at about $760M/yr. Generation and transmission components of retail prices are expected to decrease by an average one percent. Wholesale energy prices are expected to decrease between one and two percent.

The DOE report emphasizes that "significant regional variance is projected in the changes in retail and wholesale prices." The region that is most relevant to our study is the MISO region. The DOE report results are presented by NERC subregions. MISO largely comprises parts of the MAPP, MAIN, and ECAR regions. According to the study, retail electricity prices are projected to decrease in MAPP and ECAR but increase in MAIN. Wholesale electricity prices are projected to increase in all three subregions.

Understandably, these results raise some concerns, especially for retail customers in the MAIN region. In this region, near-term wholesale prices are estimated to increase from $27/MWh to $30/MWh, and retail generation and transmission prices are estimated to increase from $37/MWh to $39/MWh. These projected increases have led some stakeholders within MISO to question whether the region, or parts of the region, is ready for energy markets.

MISO Report

On March 26, 2004, MISO issued the report, *The Benefits and Costs of Wisconsin Utilities Participating in Midwest ISO Energy Markets*. The report's stated purpose is to address concerns of Wisconsin utilities that participation in the MISO energy market will increase costs. Wisconsin relies on energy imports and experiences transmission congestion. The report conservatively estimates that the cost to serve Wisconsin load will decrease by $51M in the competitive energy market.

To calculate the benefit of market participation, the study performs two calculations using a detailed electrical and production-cost model: a calculation assuming no market and a calculation with a market in place. They use the Promo IV® modeling tool. For the no-market scenario, the model includes a hurdle rate to represent incremental transmission charges between areas and inefficiencies in bilateral markets. The market model uses Lamps to determine load payments, cost of imported power, and congestion charges. The market model also includes partial FTR payments to utilities (Tier 1 and Tier 2) and administration charges to MISO. The model is run hourly for one year. A comparison of the costs to serve Wisconsin load shows a lower cost in the market model (by about $51M with partial FTR allocation; optimal use of the FTR market could provide benefits of up to $67M).

The MISO report does not include specific pricing information. A separate MISO study using a 2004 transmission model provides some pricing information that may be used for comparison (*Midwest ISO LMP Simulation Using PROMOD IV*). These results show average Lamps (for load areas) ranging from $21/MWh to $27/MWh. The monthly average on peak is highest during July with average load-area Lamps ranging from $30/MWh to $40/MWh. The monthly average on peak is lowest during May with Lamps ranging from $15/MWh to $26/MWh. In February, the average Lamps range between $23/MWh and $30/MWh. These values are generally much lower than those calculated in the DOE SMD study described above.

Our calculations of average Lamps are in reasonable agreement with those reported by MISO. Our study does not include sufficient information to estimate cost-of-service retail prices in the no-market case. Therefore, we cannot specifically comment on the benefit of a market vs. no market in Wisconsin. However, we note that our results show a decrease in production costs with a market in place in contrast to the initial state-estimator solutions. Under reasonable assumptions (linear costs, perfect FTR allocation), this should indicate reduced consumer costs in the market scenario.

Our calculation of congestion costs does not include seams issues between the MISO and surrounding control areas. We are limited to congestion costs calculated by Lamps within MISO. We represent trade outside MISO by assuming the profile in the historical state-estimator solution. In reality, the MISO market may influence bilateral contracts. In other studies, some theoretical assumptions are applied to represent transactions costs of bilateral trade and other non-market effects. These hurdle rates differ from study to study and are likewise uncertain in true market operation. Seams issues are difficult to model and analyze in studies like ours.

Appendix B. Control Areas/Power Companies Referred to in this Study

AEWC	Allegheny Energy - Wheatland CIN
AEWI	Allegheny Energy - Wheatland IPL
ALTE	Alliant East
ALTW	Alliant West
AMRN	Ameren
CILC	Central Illinois Light Co.
CIN	Cinergy
CWLP	City WL&P-Springfield
CONS	Consumers Energy Company
DECO	Detroit Edison Company
DEVI	Duke Energy Vermillion
FE	First Energy
HE	Hoosier Energy Rural Electric Coop
IP	Illinois Power
IPL	Indianapolis Power & Light Co.
LGEE	LG&E Energy
MDU	Montana-Dakota Utility Co.
MGE	Madison Gas & Electric Company
MISO	Midwest Independent System Operator
MP	Minnesota Power Co.
NIPS	Northern Indiana Public Service Co.
NSP	Northern States Power Co.
OTP	Otter Tail Power Co.
SIPC	Southern Illinois Power Coop.
SIGE	Southern Indiana Gas & Electric
UPPC	Upper Peninsula Power Co.
WEC	Wisconsin Electric Power Company
WPS	Wisconsin Public Service Coop.