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Executive Summary

Study Background

On April 1, 2005 the Midwest ISO began operation of the Midwest Markets, a "Day-2" hourly Locational Marginal Price (LMP) energy market. Market operations include centralized unit commitment and dispatch, a Day-Ahead Energy Market, a Real-Time Energy Market, and a Financial Transmission Rights (FTR) Market. The Midwest ISO is among the largest energy markets in the world covering more than 930,000 square miles and 1,760 pricing nodes. In addition to the unprecedented geographic scope of the organization and associated markets, the Midwest ISO began in late 2001 as a greenfield organization. In fact, the Midwest ISO is the first greenfield RTO[1] with a LMP[2] and centralized dispatch market structure in North America. And, unlike other RTOs with LMP and centralized dispatch, the Midwest ISO does not at this time operate a market for contingency or operating reserves. Instead, multiple individual Balancing Authorities in the region continue to be responsible for providing contingency and operating reserves.

Exhibit ES-1:
The Midwest ISO Market Footprint[3]

Source: Midwest ISO

The Midwest ISO market startup occurred during a challenging period for optimal performance of unit commitment and centralized dispatch. Challenges faced by the Midwest ISO energy market startup included record high natural gas, oil, coal, and emission allowance prices in the second half of 2005. Hurricanes Katrina and Rita combined with international events to drive natural gas and oil prices to levels well above historical norms between August and December 2005. These high fuel prices spilled over into coal and emission allowance markets, increasing

[1] RTO - Regional Transmission Organization
[2] LMP – Locational Marginal Price
[3] Note: The Midwest ISO's reliability footprint is larger than its energy market footprint.

the costs of operations and magnifying the economic effects of any operational inefficiencies. Finally, the Northeast blackout in August 2003, which affected entities in the Midwest ISO footprint as well as elsewhere in the Eastern Interconnect, increased the focus on reliability and would be expected to result in a conservative operating bias on the part of both the Midwest ISO and market participants as unit commitment and dispatch control were transferred to the Midwest ISO.

It should be noted that these challenges notwithstanding, the Midwest ISO's operational reliability was extremely high throughout the start-up. This study does not attempt to quantify the reliability benefits of coordinated unit commitment and dispatch but is instead focused exclusively on the economic benefits of unit commitment and dispatch activities.

ICF was engaged by the Midwest ISO to review its operations during a ten month period between June 1, 2005 and March 31, 2006, and to estimate a subset of the potential and actual benefits of the Midwest ISO Day-2 operations. This report presents the results of this independent analysis along with an in depth discussion of the Midwest ISO market, analytic approach, study assumptions, and conclusions.

Study Objectives

This study examines differences in production costs resulting from the transition from a Day-1 RTO to a centrally dispatched, LMP-based Day-2 market for the period between June 2005 and March 2006. In a Day-1 RTO each Balancing Authority makes unit commitment and dispatch decisions independently. A Day-2 LMP market employs centralized unit commitment and dispatch based on offers provided by generators to optimize the use of generation and transmission.

Specifically, this study asks three primary questions:

1) What are the **theoretical maximum potential benefits** available from centralized unit commitment and dispatch in the Midwest ISO footprint?
2) What percentage of these benefits were **achievable** during the study period given that the Midwest ISO market structure lacked several key characteristics of a full Day-2 market (i.e. centrally coordinated regulation and operating reserves) during this period?
3) What **benefits were actually achieved** through operation of the Midwest ISO market between June 2005 and March 2006?

It is important to note that the first two questions address the level of potential benefits available due to varying levels of market restructuring. This question has been examined many times by ICF and other parties. As such there is both a significant body of literature and an accepted industry methodology surrounding how to measure these potential benefits.

The third question "What level of benefits were actually achieved during actual operation?", is very ambitious given the size of the Midwest ISO and has not, to our knowledge, been addressed in previous studies of major electric power marketplaces. This ambitious scope of work required close cooperation with Midwest ISO stakeholders, access to Midwest ISO operators, processing of massive amounts of historical data and development of an extremely detailed generation and transmission model of the Midwest ISO footprint. ICF feels that this study provides an excellent representation of both the potential and actual benefits in terms of the details included in the analytic framework and the quality of the analytic results. At the same time, as discussed in Chapter 4 of this report, there may be some features of the modeling which may have resulted in a conservatively low estimate of actual benefits achieved and/or a high estimate of achievable benefits.

RTO Benefits Analyzed

This analysis was designed to focus on a subset of operational benefits available from Day-2 RTO operation which are quantifiable using commercially available models that simulate unit commitment and dispatch of electric generation. The focus was on production cost savings associated with centralized operations, and hence, primarily reflects estimation of the displacement of relatively more expensive generation with relatively less expensive generation made possible by centralized operations. In most cases the simulation indicated the potential displacement of gas-fired generation with coal-fired generation. This inter-fuel optimization is particularly important in the Midwest because the natural gas generation fleet includes a disproportionate level of expensive gas-fired peaking units as opposed to intermediate or less costly gas-fired combined cycle or gas-steam facilities. Further, Midwest ISO coal plants have very low operating costs even compared to other US coal-fired powerplants. Thus, any displacement of natural gas generation with coal generation can greatly decrease operating costs. Put another way, the use of a gas plant when somewhere else inside or outside of the Midwest ISO a coal plant with spare capacity and the needed transmission is available to displace the gas plant would increase costs significantly. As such, an important goal of grid optimization is to minimize these occurrences.

The primary benefits quantified in this study were related to potential improvements associated with:

- Regional security-constrained unit commitment (SCUC);
- Regional security-constrained economic dispatch (SCED);
- Improved utilization of existing transmission assets.

Some benefits of the RTO structure are more difficult to quantify than others, take significant time to be realized as they are associated with long-term capital investments, and lack industry accepted methodologies for their estimation. As a result, the following benefits are not assessed and are not reflected in the benefits estimate in this analysis:

- Reductions in planning reserve margins for generating capacity due to the increased reliability made possible by RTO information systems and inter-RTO coordination;
- Regionally coordinated transmission expansion planning;
- Improved long-term transmission and generation investment efficiency associated with improved visibility of congestion and its economic effects resulting from increased price transparency;
- Transmission access, expanded markets & reduced barriers to trade;
- Improved reliability through regional power flow visibility and dispatch;
- Improved generator availability and efficiency in peak price periods;

- Opportunities for greater participation of price responsive demand;

In order to simplify nomenclature, note that while the term "maximum potential benefits" is used in this study, it refers to the distinct subset of benefits described above, i.e., reductions in fuel and other variable operating costs under centrally coordinated rather than individual utility operations.

Analytic Approach and Cases Examined

An estimation of the benefits to be obtained from RTO operations by definition involves a comparison of what did occur ("actual Day-2 operations") to what would have occurred but for the existence of the RTO ("estimated Day-1 operations"). A simple comparison of 2004 actual operations (pre-Day-2) to 2005 operations (post-Day-2) is inappropriate due to a host of factors that include extreme variation in load, fuel prices, emission allowances prices, available generation, etc. Thus, ICF utilized a combination of historical data and detailed model analysis to develop estimates of maximum potential, achievable, and actual realized benefits of centralized dispatch in the Midwest ISO.

The primary analysis tool utilized was the GE Energy MAPS™ software model (MAPS) which is specifically designed for analysis of grid operations. MAPS was used to perform a security constrained unit commitment (SCUC) and a security constrained economic dispatch (SCED) of all generating facilities to meet peak and energy demand and operating reserve requirements in the Eastern Interconnect with a specific focus on the Midwest ISO footprint. MAPS is capable of simulating both a centralized dispatch regime in Midwest ISO (Day-2) and a Balancing Authority dispatch regime (Day-1).

Historical data derived from the Midwest ISO settlement system was utilized to calculate an estimate of the actual costs incurred during the study period. All scenarios used comparable facility operational characteristics, fuel prices, and emission allowance costs.

ICF prepared and analyzed four primary cases[4] in order to develop the study results. Each case involved a ten month study period between June 1, 2005 and March 31, 2006. These cases are:

- **Day-1 Case**: This case estimated the production cost of the Midwest ISO market assuming continued Day-1 operation for the study period. ICF used hurdle rates[5] derived from a model calibration exercise of the 2004 Day-1 Midwest ISO market to simulate continuation of decentralized Balancing Authority unit commitment and economic dispatch. Hurdle rates are the barriers to trade between Balancing Authorities needed to reproduce the actual operations observed in 2004 in the model.
- **Day-2 Optimal Case**: This case was designed to predict the theoretical maximum benefits from centralized operations in a Day-2[6] market as compared

™ MAPS is a registered trademark of General Electric Company

[4] Note that several additional cases including calibration and sensitivity cases were examined during this analysis and are discussed in Chapter 5

[5] Hurdle rates are discussed in detail in Chapter 3.

[6] Note that Midwest ISO actual operations differed significantly during the study period from the theoretical Day-2 Optimal Case modeled due to, for example, the manner in which regulation and operating reserves are currently provide in the Midwest ISO region versus the in the model representation . These differences are examined through sensitivity cases such as the "No-ASM Case".

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to the Day-1 Case. This case specifically was used to predict the production costs of an optimal Midwest ISO Day-2 operation. Commitment and dispatch hurdle rates used in the Day-1 Case to simulate decentralized operation were eliminated in the Day-2 Case to simulate centralized unit commitment and footprint-wide economic dispatch.

- **Day-2 Actual Case**: This case was designed to determine the benefits achieved by the Midwest ISO's Actual Day-2 operation over the study period. ICF used actual hourly dispatch data from the Midwest ISO's Day-2 market operations to estimate actual production costs during this historical period.
- **No-ASM (Ancillary Services Market) Case**: This sensitivity case was designed to simulate achievable benefits from centralized dispatch given the fact that current Midwest ISO operations do not include centralized dispatch and commitment of regulation and operating reserves. Instead, the majority of these ancillary services are held by each Balancing Authority locally. The Midwest ISO filed an ASM plan on February 15, 2007 that would allow for future optimization of these services beginning in 2008.

Exhibit ES-2 provides a summary of the assumptions underlying the three primary cases analyzed in the MAPS model.

Exhibit ES-2:
Comparison of Cases Examined

Parameter	Day-1 Case	No-ASM case	Day-2 Case
SCUC	Commit to meet Balancing Authority (Company) load plus reserve	Midwest ISO wide centralized commitment	
SCED	Dispatch to meet Balancing Authority load plus economy interchange	Midwest ISO wide centralized dispatch	
Transmission Utilization	Reduced actual line limit based on prior Midwest ISO analysis of historical utilization data	100 percent of the actual line limit	
Reserves	Required reserves and headroom held by each Balancing Authority	Required reserves held by each Balancing Authority; headroom held by the Midwest ISO	All reserves held optimized over the full Midwest ISO footprint.

It is from the four cases that we derive our three primary study results, namely the estimate of the maximum potential benefits associated with Midwest ISO operations, the amount of benefits achievable given the market structure in place during the study period (i.e. without ASM), and the actual benefits achieved by Midwest ISO during the study period.

The three primary study results were developed as follows:

- Maximum theoretical potential benefits were assessed as the reduction in system[7] production costs between the Day-1 Case and the Day-2 Optimal Case.

[7] The System in this case is the US Eastern Interconnect

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Because the only change between these cases is the simulated market structure within the Midwest ISO footprint any reductions in production costs are directly attributable to operation of the Midwest ISO Day-2 market.

- Achievable benefits were assessed as the reduction in system production costs between the Day-1 Case and the No-ASM case.
- Actual achieved benefits were assessed as the reduction in system production costs between the Day-1 Case and the Day-2 Actual Case.

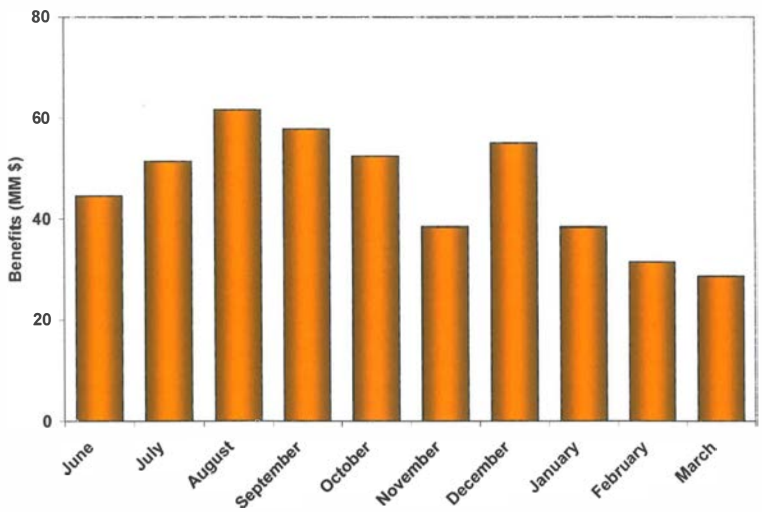
In each of the three cases the system production costs comprise the hourly fuel, variable operation and maintainence, NO_x emission allowance, and SO_2 emission allowance costs of every generator in the US Eastern Interconnect[8].

Detailed discussions of the analytic approach, calibration process, and cases examined is presented in Chapter Three.

Summary of Findings

Results of the ICF study indicate that the Day-2 market within the Midwest ISO footprint offers the potential for significant savings. Specifically, production cost savings of $460 million were estimated as the maximum benefits available to the Midwest ISO in an optimally operated Day-2 market including fully optimized reserves. This is $46 million per month on average. If this monthly level of benefits is assumed to be achieved for a 12 month period annual benefits would be $552 million. Exhibit ES-3 presents the maximum monthly benefits available in the Day-2 Optimal Case for the June 2005 to March 2006 period.

Exhibit ES-3:
Summary of Maximum Potential Benefits - June 2005 through March 2006



[8] Note that in the Day-2 Actual case only Midwest ISO generators are directly observable. This is discussed in detail in the Day-2 Actual methodology discussion below.

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Exhibit ES-4 compares the maximum potential, achievable, and actual achieved benefits for the Midwest ISO during the ten month study period. The benefits are also shown on an annualized basis assuming that average benefits extended at the same average level for an additional two months.

Exhibit ES-4:
Summary of Midwest ISO Benefits – June 2005 through March 2006

Category	Benefits ($million)	Annualized Benefits ($million)
Theoretical Maximum Potential Benefits	460	552
Estimated Achievable Benefits Given Current Market Structure	271	325
Actual Benefits Achieved	58	70

Our analysis yields the following three primary results:

- Up to $460 million in benefits were potentially achievable through optimal operation of the Midwest ISO grid during the study period. This represents a 3.8 percent decrease in overall Midwest ISO production costs compared to the parallel Day-1 estimate. This level of potential benefits is comparable to other studies of the potential benefits of centralized dispatch.[9]
- Of the $460 million in maximum potential benefits we estimate that approximately $271 million was actually achievable during the study horizon given the existing treatment of ancillary services. This represents 59 percent of the total potential and indicates that optimization of ancillary services is an important component of potential RTO savings. This $271 million translates to $325 million on an annualized basis.
- Of the $271 million achievable benefits, $58 million was realized through Midwest ISO operation of the grid. This translates to 21 percent of the achievable benefits. This $58 million is equivalent to $70 million on an annualized basis.

In order to analyze trends in the study results, we have disaggregated results on a monthly basis. Exhibit ES-5 presents the actual benefits achieved on a monthly basis for the study period along with monthly average natural gas prices.

[9] See Chapter 4 for a summary of previous study findings.

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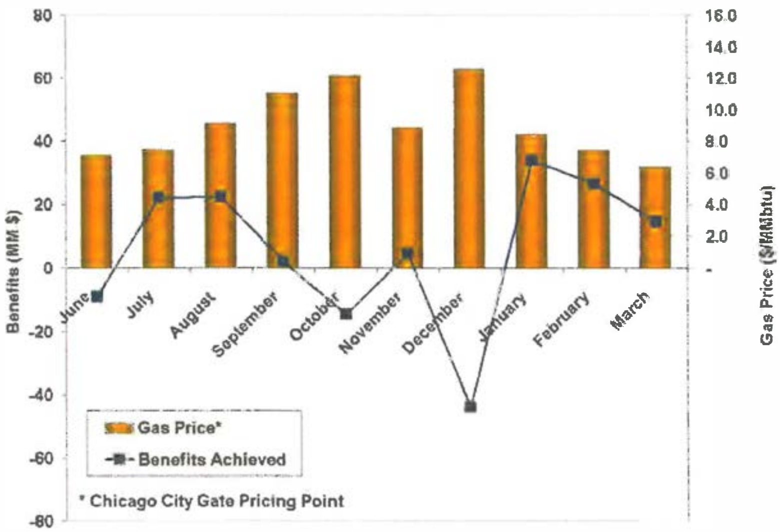
Exhibit ES-5:
Monthly Benefits Achieved and Historical Natural Gas Prices



This monthly analysis yields the following two secondary results:

- While benefits were lower during initial start up, significant improvement was demonstrated towards the end of the period. Benefits in the 2006 period were close to the maximum achievable absent optimization of ancillary services.

- The unprecedented period of high natural gas, coal, and emission allowance prices between September and December 2005 correlate with periods of lower achieved benefits, and in some cases increased costs, for Midwest ISO Day-2 compared to what was forecast for Day-1. Even as operations appear to have been improving (as seen in other data), the costs of sub-optimal commitment and dispatch were increasing due to rising generation input costs. In this environment, the cost impacts of even small incremental deviations from Day-1 optimization between gas and coal generation are economically magnified.

Conclusions

The overall outcome of this analysis demonstrates that potential RTO benefits are large and are measured in hundreds of millions of dollars per year. While on a percentage basis the potential improvement appears modest, the magnitude of the production costs involved is so large that on a dollar basis, the efficiency improvements are substantial.

RTO operational benefits are largely associated with the improved ability to displace gas generation with coal generation, more efficient use of coal generation, and better use of import potential. These benefits will likely grow over time as:

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- Reliance on natural gas generation within the Midwest ISO footprint grows as a result of the ongoing load growth and a general lack of non gas-fired development over the last 20 years. This may increase the scope for potential savings from centralized dispatch in future years.
- Tightening environmental controls and the resulting greater diversity in coal plant fleet variable operating costs will make optimization of coal plant utilization more important in future years.
- Tightening supply margins throughout the Eastern Interconnect over the next three to five years increase the importance of optimizing interchange with neighbors such as PJM, SPP, and others.
- Transmission upgrades which could increase the geographic scope of optimization within the Midwest ISO footprint.

The lack of an Ancillary Services Market (ASM) for footprint-wide reserve optimization limited the achievable results by as much as 40 percent during the study horizon.

A confluence of factors led to less than 100 percent of the achievable benefits realized during the study horizon. These include:

- The learning curve faced by both Midwest ISO and market participants during market inception resulted in suboptimal commitment and dispatch which limited achieved benefits; and
- Suboptimal commitment and dispatch during periods of extremely high gas prices had a significantly adverse impact on achieved versus potentially available benefits. This is because even small deviations from optimal dispatch can have large effects during extreme market conditions.

October and December 2005 were especially challenging periods for Midwest ISO operations due to record high fuel prices. For example, natural gas prices peaked at an average of $12.60/MMBtu in December 2005[10]. We note that had actual benefits achieved in December and October been at the average level for all other months in the study period total achieved benefits would have exceeded $146 million[11] or up to 54 percent of the total achievable benefits.

The percentage of benefits achieved showed an increasing trend over the study horizon, indicating increasingly efficient operations. This is especially evident in 2006 when fuel prices began to moderate.

We further note that major developments led by the Midwest ISO will likely increase both the potential and achieved benefits on a going forward basis. These developments include the introduction of the Ancillary Services Market which is currently under review by FERC and expected to begin operation in 2008 and regional transmission investment initiatives such as MTEP 06 which will bring $3.6 billion in transmission investments to market by 2011 and targets elimination of 22 of the top 30 constraints in the footprint.

[10] Source: Gas Daily; Chicago City Gate price

[11] This illustrative back-of-the-envelope calculation assumes that losses of $14 and $43 million in October and December are replaced with savings of $14.5 million, the average achieved in the remaining months of the study.

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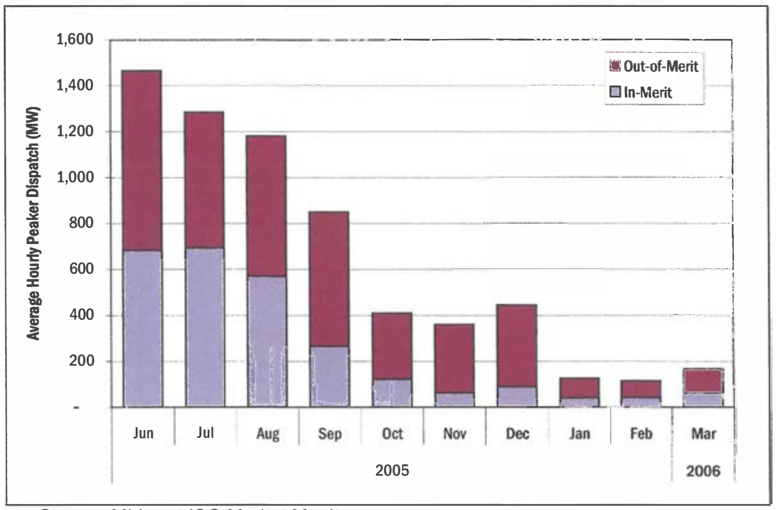
Comparison to Results in Similar Analyses

ICF's findings in this study are consistent with several previous analyses. Exhibit ES-6 is an excerpt from the Market Monitor report highlighting economic and non-economic peaking unit dispatch in the Midwest ISO. Summer 2005 shows large amounts of out-of-merit peaking dispatch. While there is less in October and December, it is still above 2006 levels. The lower 2006 levels support our findings of an improving trend. The combination of out-of-merit dispatch and extremely high fuel prices yields is consistent with the study results indicating negative benefits achieved during the months of October and December 2005. Note, that the Market Monitor definition of out-of-merit dispatch does not precisely correspond to the definition of "economic dispatch" in the ICF study associated with market rules, and hence, care needs to be exercised in comparing the two analyses.

Exhibit ES-6:
Market Monitor Analysis of the Dispatch of Peaking Resources



Source: Midwest ISO Market Monitor

Our study results are also similar to a Midwest ISO review of Revenue Sufficiency Guarantee (RSG) trends shown in Exhibit ES-7 below. Here we see RSG payments by month are high in 2005 compared to 2006. Since these are payments for units not otherwise recovering their costs, the trend also supports our conclusion of improving performance.

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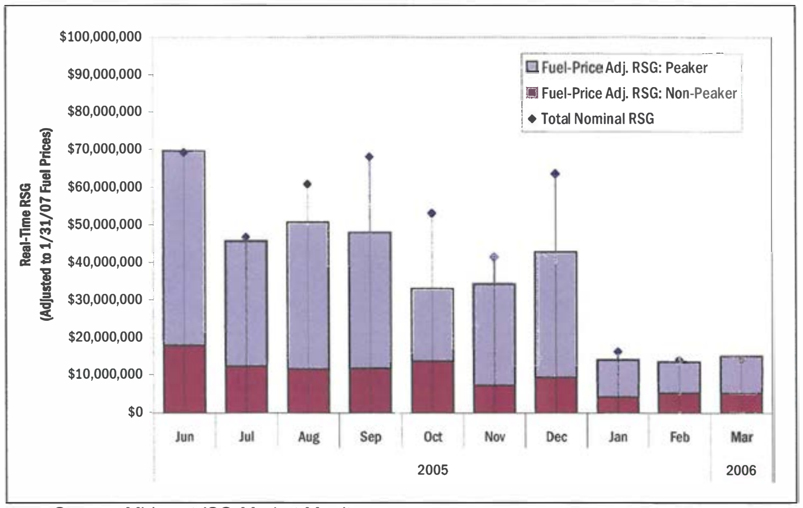
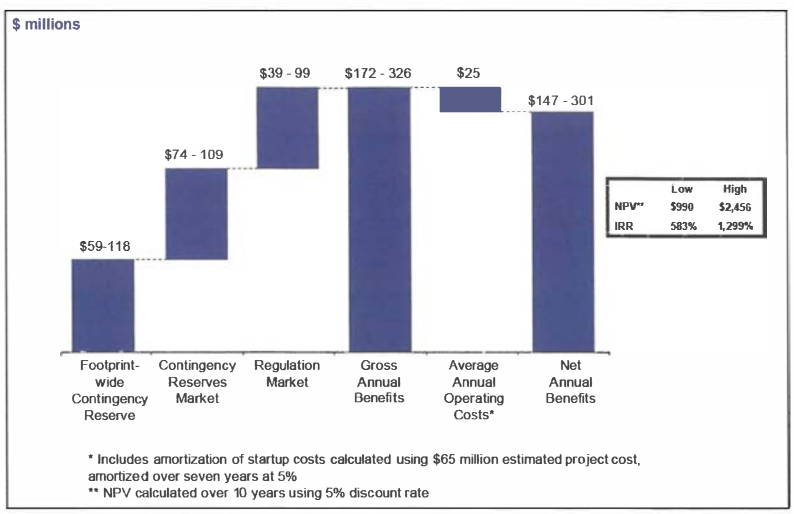
Exhibit ES-7:
Market Monitor Analysis of the Midwest ISO RSG Payments



Source: Midwest ISO Market Monitor

While the ICF study of the proposed Midwest ISO ASM market is not as detailed regarding reserves as that contained in a recent Midwest ISO filing, the theoretical value generated by ICF is within the range of the Midwest ISO value estimates generated and shown in the April 3, 2006 Filing to FERC where the comparable potential benefits are shown as $113 to $208 million (see the "contingency reserves" and "regulation market" bars in Exhibit ES-8 below).

Exhibit ES-8:
Midwest ISO Estimates of ASM Benefits and Costs



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Source: Midwest Contingency Reserve Sharing and Midwest ISO Ancillary Services Market – Project Update, October 10, 2006

In conclusion, our findings indicate that substantial benefits are available and that an increasing percentage of those benefits were realized in the later months of the study. Further, we note that expected developments such as the proposed Midwest ISO ASM market will expand the scope of potential and achieved benefits on a going forward basis. The remainder of this report is organized in four primary chapters designed to paint a full picture of this study. These are:

- Chapter One: Evolution of the Midwest ISO
- Chapter Two: Analytic Approach and Cases Examined
- Chapter Three: Overview of Modeling Assumptions
- Chapter Four: Detailed Study Result and Conclusions

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CHAPTER ONE: EVOLUTION OF THE MIDWEST ISO

This chapter provides an overview of the Midwest ISO, including a regional perspective, and a summary of the past, present and future market structures. We discuss the region before the Midwest ISO was created, outline its most recent transition from a Day-1 to Day-2 market and provide some insight into the planned ancillary services market. Our discussion of market structure examines the Midwest ISO's unique history as the only truly greenfield RTO in the US. In a span of little more than a decade the Midwest ISO has evolved from a voluntary association of a few transmission owners to one of the largest energy markets in the world. Unlike similar RTO markets in the east, the Midwest ISO market did not develop out of pre-existing pooling arrangements under which centralized unit commitment and dispatch among multiple utilities was conducted prior to market implementation.

Regional Overview of the Midwest ISO[12]

Introduction

The Midwest ISO is a non-profit, member-based Regional Transmission Organization (RTO) covering all or portions of 15 US Midwestern states and the Canadian province of Manitoba. The Midwest ISO has a dual responsibility as a reliability coordinator for electric utilities that have transferred functional control over their transmission assets as well as those that have not and as a manager of an energy market for the electric utilities that have transferred functional control to the Midwest ISO. Exhibit 1-1 below shows the reliability footprint whereas Exhibit 1-2 shows the smaller market footprint.

[12] From the Midwest ISO website unless otherwise noted.

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Exhibit 1-1:
Midwest ISO Reliability Footprint

Source: Midwest ISO

Exhibit 1-2:
Midwest ISO's Market Footprint

Source: Midwest ISO

Exhibit 1-3 provides summary statistics about the Midwest ISO's market and operations. The Midwest ISO covers an extremely large geographic area. This yields both significant scope for efficiency improvement due to RTO operations and significant challenges for development and implementation of a new market. Note also that the expansiveness of this area would also tend to complicate the efforts of market participants to optimize generation and transmission operations in a bilateral Day-0 or Day-1 marketplace.

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Exhibit 1-3:
Midwest ISO Overview

Metric	Parameter
Territory	920,000 square miles covering 15 US states and Canadian province of Manitoba. Control centers in Carmel, IN and St. Paul, MN
Market Participants	256 including 28 Transmission Owners with $13.9 billion in transmission assets under the Midwest ISO's functional control and 69 non-transmission owners
Generation Capacity	133,006 MW (market); 162,981 MW (reliability)
Peak Load (set July 31st, 2006)	116,030 MW (market); 136,520 MW (reliability)
Transmission	93,600 miles including 500kV, 345kV, 230kV, 161kV, 138kV, 120kV, 115kV, 69kV
Market Operations	Uses security-constrained unit commitment and economic dispatch of generation. Operates Day-Ahead Market, Real-Time Market, and Financial Transmission Rights (FTR) Market. Administers Open Access Transmission and Energy Markets Tariff ("TEMT")
Balancing Authorities	36 (reliability footprint)

Source: Midwest ISO Corporate Information Fact Sheet as of February 2007

The Midwest ISO energy market features security-constrained unit commitment and economic dispatch of generation with LMPs produced for 1,760 pricing nodes. Market operations include a Day-Ahead Market, a Real-Time Market, and an FTR Market. The Midwest ISO is responsible for administering the Open Access Transmission and Energy Markets Tariff (TEMT) mandated by the Federal Energy Regulatory Commission (FERC), the primary regulator of the wholesale US electricity sector.

As mentioned above, the Midwest ISO is both a reliability coordinator as well as an energy market operator. Exhibit 1-4 graphically represents the Midwest ISO's relationship with each Balancing Authority, whether primarily as a market operator or reliability coordinator. In addition, the Midwest ISO provides contractual services under agreements with Duke Power, MAPPCOR and the Midwest Contingency Reserve Sharing Group.

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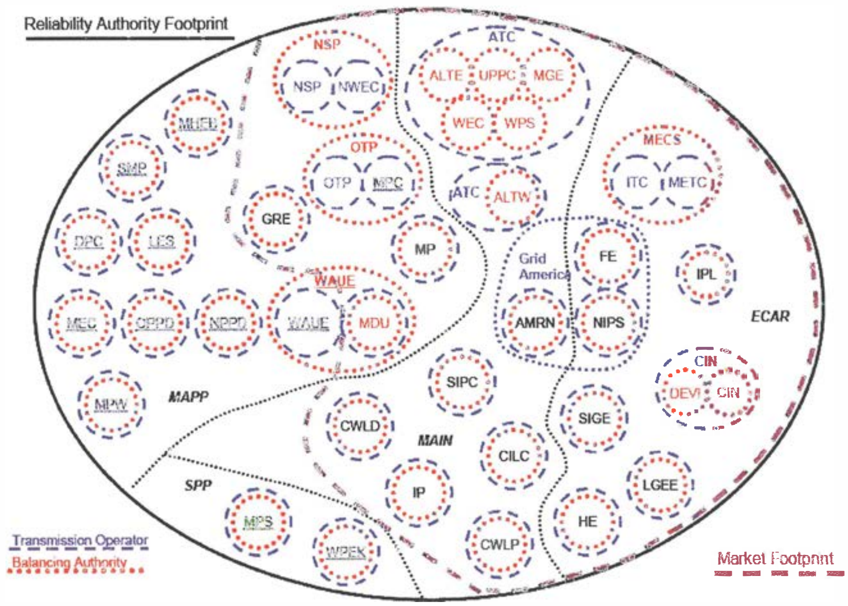
Exhibit 1-4:
Midwest ISO Balancing Authorities[13]



Note 1: Systems under Midwest ISO Reliability Authority but not under the Energy Markets are shown as underlined.
Note 2: MDU is a pseudo Balancing Authority under Midwest ISO.
Note 3: ITC and METC are treated as separate Balancing Authorities for the Energy Markets.

Source: Midwest ISO Business Practices Manual for Coordinated Reliability, Dispatch, & Control, Manual No. 006, 2005. Note that GridAmerica and ATC are no longer operational but the Balancing Authorities pictured are valid up to the end of the study period in March 2006. Since then, DEVI and LGEE are no longer operational (6/2006 and 9/2006, respectively) and SMP joined the market footprint (4/2006).

Midwest ISO Supply Mix

The Midwest ISO is one of the largest markets in the US with a net internal peak demand over 116 GW[14] and has a bimodal winter and summer peaking profile. Exhibit 1-5 shows the percentage breakdown of dispatch and capacity by generation source for the study horizon from June 2005 through to March 2006. During this time, generation for the ten months of the study period reached 488 TWh and capacity within the Midwest ISO was about 138 GW. Thus, the ratio of capacity to peak was approximately 119 percent.

[13] See Chapter 4 for a mapping of company acronyms.
[14] The peak demand record for Midwest ISO's market footprint of 116,030 MW was set on July 31, 2006.

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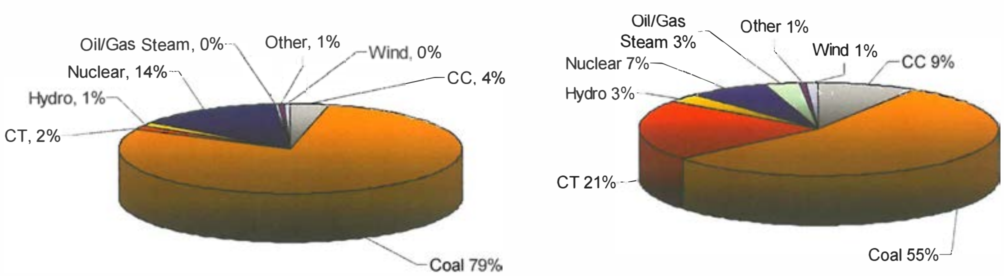
Exhibit 1-5:
Generation and Capacity, June 2005 – March 2006



Generation (492 TWh) **Capacity (138 GW[1])**

Source: Midwest ISO and ICF

Although the Midwest ISO exports energy during the study period, it is ultimately a net importer. On average, the Midwest ISO was a net exporter to SPP and IMO. The monthly average net export during the 10 study months was 306 MW per hour to SPP and 841 MW per hour to IMO, yielding a total of 1,147 MW per hour or 8 TWh over the ten months. On the other hand, the Midwest ISO imported on average 1,631 MW per hour from PJM, 1,543 MW per hour from Manitoba Hydro, 353 MW per hour from MAPP, and 1,613 MW per hour from SERC, yielding a total of 4,027 MW per hour or 29 TWh over the ten months. Note that Manitoba Hydro alone accounts for 38.3 percent of this generation import. This is 2.3 percent of the 492 TWh total. Overall, the Midwest ISO is a net importer of 2,880 MW per hour (4,027 MW per hour imports net 1,147 MW per hour exports) or 21 TWh over the ten months.

It is important to note that reliance on natural gas-fired generation capacity has been increasing in the Midwest ISO area in recent years where virtually all of the generation capacity added in the past decade relies on natural gas as its primary fuel. In fact, of the total capacity added to the Midwest ISO footprint in the past decade more than 92 percent is gas-fired. Furthermore, 72 percent of the existing gas capacity in the Midwest ISO is considered to be peaking capacity (i.e. gas-steam or combustion turbine). Hence, use of natural gas could well require the use of very costly sources from within this fuel category. The increased reliance on natural gas throughout the region is further evidenced in the January 2007 Midwest ISO Operations Report[15] which indicates that natural gas-fired generation was the marginal generation resource more that 30 percent of the time in January 2007 even though combined cycle and combustion turbine operation only accounted for 6 percent of total generation.

Midwest ISO's Interconnectivity with the Rest of the Grid

Electrically, the Midwest ISO is part of the Eastern Interconnection, the largest of the four distinct synchronous power grids in North America. As Exhibit 1-6 shows, the Midwest ISO system interconnects with the Ontario Independent Electricity System Operator to the north, the PJM Interconnection to the east, the Southwest Power Pool (SPP RTO) to the southwest and

[15] Midwest ISO Market Operations Report; January 2007

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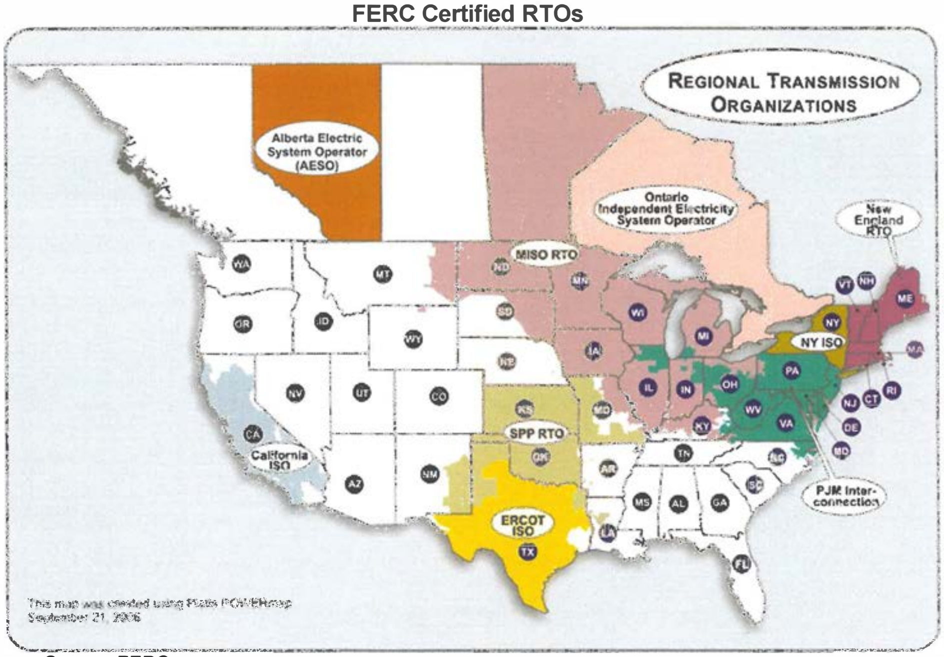
the Tennessee Valley Authority to the south.[16] The Midwest ISO has seams agreements or memorandums of understanding with each of these organizations but has forged the closest relationship with PJM, the region with which the Midwest ISO shares the largest and most complex border. Note that portions of PJM are nearly surrounded by the Midwest ISO (e.g. the Chicago area).

Exhibit 1-6:
FERC Certified RTOs



Source: FERC

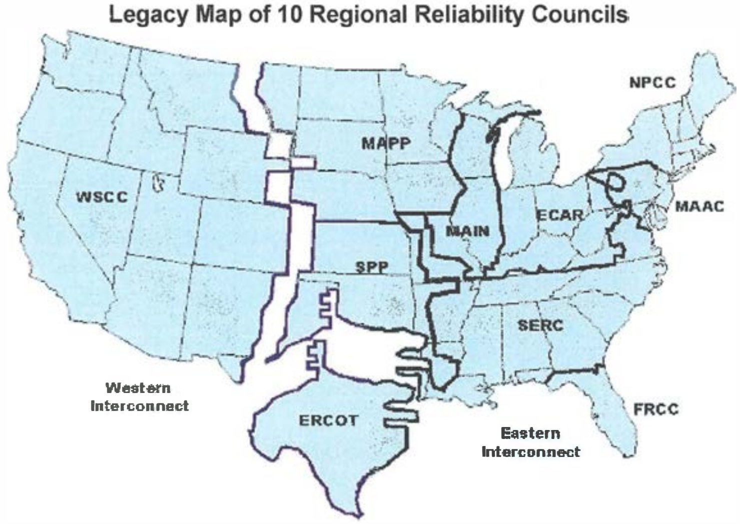
In 2002 the FERC directed the Midwest ISO and PJM to work toward development of a common market by October 1, 2004 in order to harmonize their practices to functionally create a single, transparent energy market.[17] The creation of a “joint and common” market for PJM and the Midwest ISO goes well beyond the “seams” coordination agreements between other neighboring RTOs. This Midwest ISO-PJM coordination agreement results in by far the largest market in the US stretching from eastern Montana through southwestern Missouri, Kentucky, Virginia, and counterclockwise through “Classic PJM”, Michigan, and Minnesota. This tremendous size and new structure are major developments enhancing the transparency and depth of the wholesale markets in the region. Under the coordination agreement and with input from stakeholders, the two RTOs have implemented mechanisms to compensate for redispatch to relieve congestion and protocols for honoring reciprocal flowgates and they continue to address seams issues and reconcile differences in products to be traded using common standards.

[16] The Tennessee Valley Authority is not shown on the map but encompasses the entire state of Tennessee and portions of contiguous states.
[17] FERC, Docket Nos. EL02-65-000, July 31, 2002.

Midwest ISO Day-0 Operation

Before the Midwest ISO was created in 1996, the region operated as a decentralized market dominated by vertically integrated, investor-owned utilities (IOUs). While there was no common market for energy, there were sub-regions that communicated and cooperated on maintaining the reliability of their shared and interconnected transmission system. The organizations leading this effort were the regional reliability councils.[18] The Midwest ISO's current geographic footprint was originally divided between four regional reliability councils: the Mid-Continent Area Power Pool (MAPP); the Mid-America Interconnected Network (MAIN); the East Central Area Reliability Coordination Agreement (ECAR); and the Southwest Power Pool (SPP). Exhibit 1-7 shows a legacy map of each council's geographic reach.

Exhibit 1-7:
Legacy Map of 10 Regional Reliability Councils



Source: NERC

These councils are composed of stakeholders from across the electric industry including IOUs, IPPs, power marketers, and end-use customers. At the time, there were 10 regional reliability councils which reported to the North American Electric Reliability Council (NERC), a self-regulating organization that developed voluntary industry standards and best practices.[19] The geographic division of these councils provides an idea of the organization of the market and how electricity flowed. Typically, connections within each council were strong but somewhat weaker when crossing boundaries or even utility footprints. In this environment, most generators would supply local demand and interregional electricity transfers would be relatively more limited. Furthermore, the reliability councils also tended to focus on reliability rather than economic concerns.

In addition to physical transmission constraints that may have limited power flows, bilateral transactions to take advantage of opportunities to optimize generation usage between areas

[18] The number of regional reliability councils and some of their footprints have changed since then and the map shown above is for reference purposes only.
[19] This has changed since and is discussed below.

was hampered by high transaction costs in the form of low market transparency and also due to transmission costs that penalized power that crossed regional or utility boundaries. For example, power sent from a source to a load far away often had to traverse several utility footprints before it reached its ultimate destination (wheeling), and was often burdened with "pancaked" transmission rates.[20] Depending on their magnitude, pancaked transmission tariffs can act as trade obstacles that effectively segment a market and limit interregional transfers. Similarly, decentralized unit commitment and dispatch operations from individual companies and Balancing Authorities increased costs and caused inefficiency relative to an optimum use of resources.

Midwest ISO Day-1 Operation

The high costs of pancaked transmission rates and the economic inefficiency of the US power market stifled non-utility generation investment and eventually led FERC to take action. On April 24, 1996 the FERC released the final ruling supporting competitive generation by mandating open access to the transmission system of incumbent utilities. FERC order 888 established a process for filing open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service.[21] This tariff was known as the Open Access Transmission Tariff (OATT) and is posted on the Open Access Same Time Information System (OASIS) website to foster transparency and liquidity.

About the same time, transmission owners in the Midwest had begun to discuss the formation of a voluntary association that would also help to eliminate trade barriers such as pancaked transmission rates. As Exhibit 1-8 shows, the Midwest ISO was established on February 12, 1996 and over the course of the next several years evolved into a regional transmission organization (RTO) and energy market operator.

Exhibit 1-8:
Key Dates in the Midwest ISO's Evolution

Date	Event	Market Type
February 12, 1996	Transmission owners convene to form the Midwest ISO	Day-0
September 16, 1998	FERC grants conditional approval as an independent system operator	
December 2001	RTO approval from FERC (first in the nation). Reliability operations (Day-1 markets) begin	Day-1
February 1, 2002	Transmission service begins under Midwest ISO Open Access Transmission Tariff	
April 1, 2005	Midwest Markets (Day-2) Launch	Day-2

On September 16, 1998, the FERC approved the application from 10 transmission-owning utilities in the Midwest to transfer functional control of their jurisdictional transmission facilities to the Midwest ISO and establish an open access transmission tariff.[22] The original 10 companies

[20] "Pancaked transmission rates" is a term commonly used to describe the practice of incurring multiple wheeling charges when moving power from one area to another across multiple utility territories, each with its own transmission system costs and associated wheeling charge. Since the tariff charges do not correlate with and almost always exceed marginal costs, they are economically inefficient.
[21] FERC, Docket No. RM95-8-000, Order 888, April 24, 1996.
[22] FERC, Docket No. ER98-1438-000, EC98-24-000, September 16, 1998.

were: Cincinnati Gas & Electric Company; Commonwealth Edison Company; Commonwealth Edison Company of Indiana; Illinois Power Company; PSI Energy, Inc.; Wisconsin Electric Power Company; Union Electric Company; Central Illinois Public Service Company; Louisville Gas & Electric Company; and Kentucky Utilities Company.[23]

The Midwest ISO's initiative went well beyond the mandate of Order 888 because it created an actual separation of duties rather than relying on a standard transmission tariff to decrease discrimination and end pancaked rates. Even though the transmission owners would retain ownership of their transmission facilities and physically operate and maintain them, they would turn over functional control and tariff administration responsibilities to the Midwest ISO to both provide non-discriminatory open access to the regional transmission grid and to increase system security and reliability. This structure would provide substantial benefits to transmission customers by:

- Eliminating transmission rate pancaking on a regional scale thereby producing an overall reduction in the costs of transmitting energy within the region;
- Offering one stop shopping for transmission service;
- Establishing uniform and clear rules by the ISO/RTO;
- Separating control over transmission facilities from generation and marketing functions;
- Allowing large scale regional coordination and planning of transmission;
- Enhancing reliability; and
- Fostering competition with sellers having access to more markets for their products and buyers having greater access to sources of supply.[24]

Encouraged by the Midwest ISO and other first movers in the industry, the FERC later released another final ruling on December 20, 1999 to spur the formation of RTOs nation-wide. While the FERC stopped short of a mandate in Order 2000, it did make it clear that RTO formation was preferred and that the Commission was ready to review and certify RTOs that met a series of requirements aimed at eliminating discrimination.[25] On December 21, 2001, the Midwest ISO became the first RTO in the nation certified by the FERC which heralded the Midwest ISO's move into a Day-1 market. It began providing transmission service under its approved OATT on February 1, 2002 and incorporated other hallmarks of Day-1 operation such as OASIS administration, Available and Total Transfer Capability (ATC and TTC) determination, Security Coordination, Transmission Planning, System Operations, and Market Monitoring.

[23] Originally there were 25 transmission-owning utilities involved in the creation of the Midwest ISO representing most of the transmission owners in MAIN and ECAR. Several of these utilities attempted to form their own RTOs but none have materialized and the Midwest ISO subsequently absorbed many of them into its expanding footprint.
[24] FERC, "Benefits Claimed by Applicants," Docket No. ER98-1438-000, EC98-24-000, September 16, 1998.
[25] Four characteristics: (1) independence from market participants; (2) appropriate scope and configuration; (3) operational authority over transmission facilities within the region; and (4) exclusive authority to maintain short-term reliability. Nine functions: (1) design and administer its own tariff; (2) manage congestion; (3) address parallel path flow; (4) serve as provider of last resort of all ancillary services; (5) administer its own OASIS and independently calculate TTC and ATC; (6) provide for objective monitoring of the markets it operates or administers; (7) take primary responsibility for planning and expansion of transmission facilities; and (8) participate in interregional coordination of reliability practices.

Market monitoring functions were also added, but were minimal, reflecting the then current bilateral market. In addition, the Midwest ISO relied exclusively on non-market mechanisms such as Transmission Loading Relief (TLR) calls with associated generation re-dispatch performed by the individual Balancing Authorities to manage transmission congestion.

Unlike other RTOs, the Midwest ISO was unique because the Balancing Authorities in its footprint work in tandem with the Midwest ISO, but were not part of the RTO organization. The Balancing Authorities continue to be part of their parent utility organizations and perform necessary functions such as balancing generation with load in their respective geographic regions and retaining responsibility for unit commitment and economic dispatch of generation to serve their load. The Balancing Authorities self-provided their ancillary services needs and administer operating reserves. They also maintain primary responsibility for ensuring resource adequacy.

Regulatory and Industry Challenges Affecting the Midwest ISO's Day-1 Operations

During this time, much was changing in the industry. The directive from the FERC spurred the creation of several other RTOs in the region which have all now dissolved. The effect on the Midwest ISO was an ever-changing membership base and thus geographic scope. By the time FERC approved the Midwest ISO's RTO application, Commonwealth Edison Company, Illinois Power Company and Ameren had withdrawn to join other RTOs (though the latter two merged and then rejoined the Midwest ISO in 2004). On the other hand, eight more utilities joined the Midwest ISO, namely: Indianapolis Power & Light; Indiana Municipal Power Agency; Lincoln Electric (Neb.) System; Minnesota Power; Otter Tail Power Company; UtiliCorp United (including Missouri Public Service, St. Joseph Light & Power and WestPlains Energy-Kansas); City Water, Light and Power (Springfield, Ill.); and Montana-Dakota Utilities. In addition, Manitoba Hydro entered into a coordination agreement and there were pending and conditional agreements with several other companies such as Sunflower Electric Power Corporation, Dairyland Power Cooperative, Great River Energy, and Southern Minnesota Municipal Power Agency. While this is not an exhaustive list of the changes the Midwest ISO experienced, it does underscore the difficult task the Midwest ISO had of integrating new members and its growing importance in the region. Despite these challenges, the Midwest ISO eventually became the only FERC-recognized RTO in the Midwest in December 2001.

The Midwest ISO Day-2 Operation

The Midwest ISO's Day-1 operation was an improvement over the status quo but still did not provide market-based congestion management and imbalance service as required by FERC of RTOs. Compared to its eastern neighbors, the Midwest ISO is a relative newcomer in implementing a transparent power market structure and pricing mechanisms.[26] The addition of FERC-required market-based transmission services required creation of day-ahead and real-time locational marginal price ("LMP") energy markets as had already occurred in the eastern RTOs. LMP-based energy markets would allow the Midwest ISO to efficiently manage transmission congestion and set transparent market-clearing prices at each location on the network.

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[26] PJM RTO started its bid-based energy markets in April, 1997. ISO-New England launched its first Power Exchange (PX) market in May, 1999.

The process intensified on May 26, 2004 when the FERC conditionally approved the Open Access Transmission and Energy Market Tariff (TEMT) that was filed by the Midwest ISO on March 31, 2004. The proposed TEMT, and its later modifications, provide the terms and conditions necessary to operate Day-Ahead (DA) and Real-Time (RT) energy markets with LMP-based price signals thereby implementing the FERC-required market-based congestion management system. In addition, the Midwest ISO proposed to operate a market for Financial Transmission Rights (FTR), which provides market participants the opportunity to hedge their locational price risk associated with congestion. The Midwest ISO expended a total of $246.7 million to complete the development of the systems to implement Day-2 markets and expects annual revenue of between $120 million and $125 million to recover both these startup cost and ongoing operating costs.[27]

On April 1, 2005, the Midwest ISO officially commenced Day-2 operation and began centrally dispatching wholesale electricity and transmission service throughout much of the Midwest. The bids and offers in the market for the first two months were cost-based, and hence the ICF study focuses on the post June 30, 2006 period when the bids became market-based.

Energy Market

The Midwest ISO operates Day-Ahead and Real-Time (balancing) Energy Markets using security constrained unit commitment and economic dispatch of generation that provide for an optimal use of all resources within the region based on the bids and offers provided to the RTO. The Day-Ahead Market is a forward financial market for energy. The Day-Ahead clearing process results in a set of financially binding schedules according to which sellers are financially responsible to deliver and purchasers financially responsible to buy energy at defined locations. The Day-Ahead market process is based on a unit commitment model that minimizes total production costs over 24 hours. Thus, the Midwest ISO uses a tool similar to the tool used in this study. Typically the load cleared in the Day-Ahead Energy Market is less than the actual load cleared in the Real-Time Energy Market. This imbalance requires the Midwest ISO to commit additional units through a Reliability Assessment Commitment (RAC) process in order to meet the projected Real-Time load and required reserves.

Sources of energy in the day-ahead market include:

- Generator offers
- External transactions
- Virtual supply offers

Sources of demand in the day-ahead market include:

- Fixed demand bids
- Price sensitive demand bids
- External transactions
- Virtual demand bids

27 Midwest ISO, FERC Form 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental, 109.1 and 123.1.

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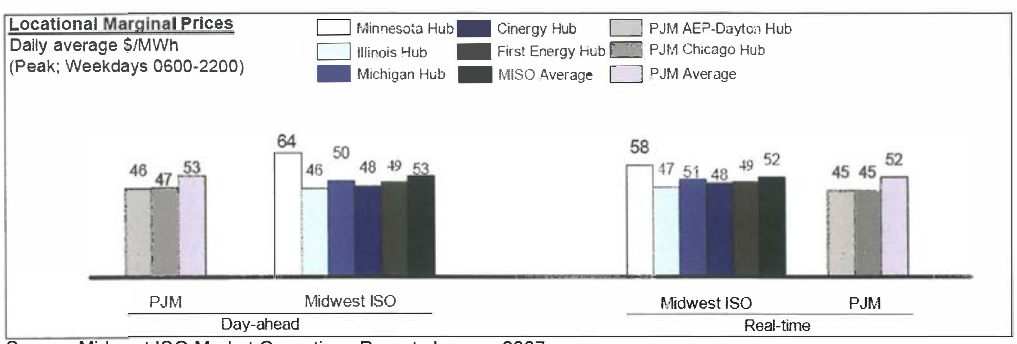
The Midwest ISO publishes a day-ahead schedule and a 24-hour day-ahead set of LMPs. The day-ahead schedules constitute financial contracts to supply or consume power. FTRs are also settled based upon the 24-hour day-ahead LMP values.

The Midwest ISO Day-Ahead market clearing process performs a unit commitment and dispatch based on supply offers and load bids and establishes hourly LMPs at each discrete price node on the grid. Those LMPs are used to settle both cleared supply and demand transactions at each price node. Generally each generator has a unique price nodes (one per generating unit, even where multiple generators are at a single plant). In contrast, due to practical metering considerations, loads are generally aggregated for settlement purposes based on the load-weighted average of the load zone.

The primary purpose of the Day-Ahead market is to clear (and schedule) sufficient supply to fully satisfy cleared Day-Ahead demand. The Day-Ahead market serves to utilize resources that minimize production costs accounting for operational limitations (e.g., unit notification and minimum start times). The purpose of the Real-Time market is similar, but is based on actual rather than bid demand and must also function to determine economic redispatch to manage congestion given dynamic supply and demand.

The Midwest ISO utilizes Locational Marginal Pricing (LMP), which is the market clearing price at a specific Commercial Pricing Node (CPNode) in the Midwest Market that is equal to the cost of supplying the next increment of load at that location. LMP values are separated into three components for settlement purposes: marginal energy component, marginal congestion component, and marginal loss component. The value of an LMP is the same whether a purchase or sale is made at that node. Since the launching of the Midwest ISO's Energy Market in April, 2005, LMPs at some 1,760 points along the power grid are produced at five-minute intervals. The Midwest ISO has created four financial trading hubs - Cinergy, Illinois, Michigan and Minnesota - that provide market participants with convenient trading locations with corresponding price indices to facilitate bilateral trading and settlement of contracts. The hubs provide stable trading locations thereby reducing price uncertainty for parties who wish to contract, improve liquidity and generally support the development of a more robust wholesale electricity market. Exhibit 1-9 shows the January 2007 average daily LMPs for current Midwest ISO hubs in both the Day-Ahead and Real-Time markets. Differences between locations are primarily the result of congestion.

Exhibit 1-9:
Midwest ISO Hub Prices – January 2007



Source: Midwest ISO Market Operations Report; January 2007

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Local Balancing Authority Operators (also known Balancing Authorities) continue to be responsible for many of their traditional functions, but operate their systems in response to signals issued by the Midwest ISO.

FTR Market

Although energy is the principal offering in the market, the Midwest ISO also provides tradable Financial Transmission Rights (FTRs) to allow market participants to hedge potential congestion costs. FTRs are allocated annually to market participants on the basis of historic transmission service. Immediately following the annual FTR allocation, the Midwest ISO also conducts an annual FTR auction. The Midwest ISO also conducts a monthly allocation and auction of FTRs to facilitate trading and to provide a measure of FTR market price transparency, although only final strike prices are published (bids, offers, and identities of market participants are confidential).

Currently the Midwest ISO FTR market includes FTR obligations. Obligations provide revenues to the holder if congestion restricts transmission from the FTR Receipt Point to the FTR Delivery Point. If congestion is in the reverse direction, they impose a charge on the holder.

The Midwest ISO TEMT also provides for the eventual introduction of FTR options. These instruments provide revenues to the holder if congestion restricts transmission from the FTR Receipt Point to the FTR Delivery Point. If congestion is in the reverse direction, no charge is imposed on the holder.

Capacity and Ancillary Services Markets

There is currently no capacity market operated by the Midwest ISO, and resource adequacy continues to be addressed at the regional and state level. Module E of the TEMT addresses Resource Adequacy requirements, including planning reserve margin requirements for market participants serving load within the Midwest ISO footprint. The Midwest ISO adequacy requirements are based on existing Reliability Resource Organization (RRO) and state standards. According to Module E, transmission customers serving network load must designate firm Network Resources relied upon to assure adequate generation is available to meet both load and applicable reserve requirements.

Planning reserve requirements in the Midwest ISO footprint varied by NERC Region during the study period. At the time, MAPP and MAIN each had a 15 percent planning reserve requirement while ECAR had no explicit planning reserve requirement. In place of planning reserve requirements, ECAR reviews available and planned capacity and performs a probabilistic Loss of Load Expectation (LOLE) to determine if sufficient capacity exists to meet forecast demand in both the short and long term. The target LOLE is 1 day in 10 years (0.1 day/year). Similar to the capacity market, markets for operating reserves and ancillary services are expected to be developed in the future (see Day-3 discussion below).

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Regulatory and Industry Challenges Affecting the Midwest ISO's Day-2 Operations

While the Midwest ISO was developing plans to transition to a Day-2 operation, the [28] August 14, 2004 blackout, affected Midwest ISO members and others, and increased reliability concerns. The Energy Policy Act of 2005 specifically addressed this by empowering the FERC to designate a single Electric Reliability Organization for the country with the ability to create and enforce mandatory reliability standards on the entire US electric industry, subject to the FERC's approval. On July 20, 2006, the NERC was certified as the Electric Reliability Organization and its proposed reliability standards are currently under the FERC's review.

Additional challenges faced by the Midwest ISO energy market startup included record high natural gas, oil, coal, and emission allowance prices in the second half of 2005. Hurricanes Katrina and Rita combined with international events to drive natural gas and oil prices to levels well above historical norms between August and December 2005. For example, natural gas prices peaked at an average of $12.60/MMBtu in December 2005. [29] These high prices spilled over into coal and emission allowance markets, increasing the costs of operations and magnifying the economic effects of any operational inefficiencies experienced during initial market operations.

Comparative Analysis

This section offers a high level comparison of the evolutionary stages the Midwest ISO has progressed through. We offer this summary before we introduce the Midwest ISO's proposed ancillary services market in the next section. Exhibit 1-10 compares the division of responsibilities between the Day-0, Day-1 and Day-2 operations.

[28] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, 1 (April 2004).
[29] Source: Gas Daily Chicago City Gate price

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Exhibit 1-10:
Roles and Responsibilities During Day-0, Day-1 and Day-2 Operation

Responsibilities	Day-0	Day-1	Day-2
OASIS Administration[1]	Balancing Authority	Midwest ISO	Midwest ISO
OATT Tariff Administration[1]	Balancing Authority	Midwest ISO	Midwest ISO
ATC and TTC Calculation	Balancing Authority	Midwest ISO	Midwest ISO
Load Forecasting	Balancing Authority	Balancing Authority	Balancing Authority
Outage Scheduling	Balancing Authority	Midwest ISO	Midwest ISO
Security Coordination	Balancing Authority	Balancing Authority/ Midwest ISO	Midwest ISO
Transmission Planning	Balancing Authority	Midwest ISO	Midwest ISO
Unit Commitment and Dispatch	Balancing Authority	Balancing Authority	Midwest ISO
Congestion Management	Balancing Authority (redispatch/TLR)	Midwest ISO (redispatch/TLR)	Midwest ISO (LMP)
Resource Adequacy	Balancing Authority	Balancing Authority	Balancing Authority
FTR Market Management	N/A	N/A	Midwest ISO
Day-Ahead and Real-time Market Administration	N/A	N/A	Midwest ISO
Billing and Settlement	N/A	Midwest ISO	Midwest ISO
Market Monitor	N/A	Independent (Minimal)	Independent

[1] Individual utility OASIS sites and OATTs were in effect under Day-0 operation

In the decentralized Day-0 market, all functions were the responsibility of the local Balancing Authority. In contrast, the Midwest ISO took over some of these responsibilities in the Day-1 market. Between Day-0 and Day-1, the depth of coordination between the Midwest ISO and Balancing Authorities is dramatically different. The salient distinction is that each Balancing Authority was responsible for a small geographic footprint with limited regional coordination

Under Day-2 operation, the Midwest ISO expanded its Day-1 responsibilities to include a market-based method for managing congestion featuring operation of Day-Ahead and Real-Time energy markets, and a market for FTRs. Because of the introduction of a Day-Ahead market, a Real-Time market and an FTR market, the need for market monitoring responsibilities for Day-2 increased significantly. Those responsibilities are currently carried out by an Independent Market Monitor (IMM), Potomac Economics. The Midwest ISO manages the single Midwest ISO-wide transmission tariff under both Day-1 and Day-2 operations. Under both Day-1 and Day-2 operation, all market participants take transmission service from the Midwest ISO under its tariff.

As described in this chapter, while the physical fundamentals remain largely unchanged in the Day-1 and Day-2 scenarios, there are significant structural and operational differences, especially in key operational areas such as unit commitment and dispatch, transmission scheduling, and congestion management. Specifically, there is centralized operation with access to greater data and the ability to apply mathematical and economic optimization to these areas.

Future Enhancements to Midwest ISO Operations

On February 15, 2007, the Midwest ISO submitted to the FERC its proposal to create an Ancillary Services Market ("ASM") for the procurement of regulation and operating reserves.[30] Some refer to this proposed structure as a "Day-3" market to differentiate it from the existing Midwest ISO operations. In order to prepare for the implementation of ASM, the Midwest ISO proposes to assume the role of the single Midwest ISO Balancing Authority with the majority of the current Balancing Authorities serving only as Local Balancing Authorities. The transfer of authority is to ensure that the Midwest ISO will be able to procure required operating reserves through the proposed ASM.

Currently the procurement of regulation and operating reserves is the responsibility of each Balancing Authority via a cost-based process. Energy on the other hand is procured through a market-based process from the Midwest ISO. The proposed ASM seeks to create Day-Ahead and Real-Time markets for regulation and operating reserves like those currently existing for energy in the Midwest ISO and like those currently existing in other RTOs employing LMP Day-2 structures.

The Midwest ISO has evaluated potential benefits of ASM market implementation and has found that it will greatly expand the scope of potential savings available to market participants. This conclusion is corroborated by the findings of this analysis. See Exhibit ES-8 above which summarizes the significant expected benefits and costs of the ASM market initiative based on the evaluation previously performed by the Midwest ISO.

[30] Midwest ISO, Docket No. ER07-550-000, February 15, 2007.

CHAPTER TWO
ANALYTIC APPROACH AND CASES EXAMINED

Introduction

This chapter discusses the analytic approach to analyzing the changes in production costs associated with the transition to centralized operations. This approach involves several computer model simulations of the Midwest ISO operations between June 2005 through March 2006.

It is emphasized that this estimate of the benefits from Day-2 centralized information and operations does not include some of the other potential benefits associated with market restructuring, which may best be treated on a qualitative basis.

The approach to estimating the three primary outputs of this analysis involves calculating the difference between the Day-1 system[31] production cost and that of the respective Day-2 case. The primary outputs are: (1) the maximum theoretical savings of an Optimal Day-2 operation, (2) the achievable theoretical savings of the Midwest ISO's Day-2 operation, and (3) the estimated achieved benefits of the Day-2 Actual Midwest ISO operation.

This chapter is presented in six principal sections as follows:

- Cases Examined
- Methodology for Assessing Day-1 and Day-2 Optimal Costs in the MAPS Framework
- Model Calibration
- Modeling Treatment Across Cases
- Methodology for Assessing Day-2 Actual Costs
- Stakeholder Participation Process

Cases Examined

ICF prepared and analyzed four primary cases in order to develop the study results. These cases are:

- **Day-1 Case**: This case estimated the production cost of the Midwest ISO market assuming continued Day-1 operation for the study period. ICF used hurdle rates[32] derived from a model calibration exercise of the 2004 Day-1 Midwest ISO market to simulate continuation of decentralized Balancing Authority unit commitment and economic dispatch. Hurdle rates are the barriers to trade

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[31] The System in this case is the US Eastern Interconnect

[32] Hurdle rates are discussed in detail in Chapter 3.

between Balancing Authorities needed to reproduce the actual operations observed in 2004 in the model.

- **Day-2 Optimal Case**: This case was designed to predict the theoretical maximum benefits from centralized operations in a Day-2[33] market as compared to the Day-1 Case. This case specifically was used to predict the production costs of an optimal Midwest ISO Day-2 operation. Commitment and dispatch hurdle rates used in the Day-1 Case to simulate decentralized operation were eliminated in the Day-2 Case to simulate centralized unit commitment and footprint-wide economic dispatch.
- **Day-2 Actual Case**: This case was designed to determine the benefits achieved by the Midwest ISO's Actual Day-2 operation over the study period. ICF used actual hourly dispatch data from the Midwest ISO's Day-2 market operations to estimate actual production costs during this historical period.
- **No-ASM (Ancillary Services Market) Case**: This sensitivity case was designed to simulate achievable benefits from centralized dispatch given the fact that current Midwest ISO operations do not include centralized dispatch and commitment of regulation and operating reserves. Instead, the majority of these ancillary services are held by each Balancing Authority locally. The Midwest ISO filed an ASM plan on February 15, 2007 that would allow for future optimization of these services beginning in 2008.

From these cases, we estimate the maximum potential benefits associated with the Midwest ISO Day-2 market; the achievable benefits given the actual implementation of the Midwest ISO Day-2 market; and the actual benefits achieved by the Midwest ISO during the study period. In each case, the benefit is assessed by comparing the production cost in the Day-1 Case to that in the respective Day-2 Case. The maximum theoretical potential benefits is assessed as the change in system production costs between the Day-1 Case and the Day-2 Optimal Case; and the achievable benefits as the change in system production costs between the Day-1 Case and the No-ASM Case. In both cases, the only change relative to the Day-1 Case is the simulated market structure within the Midwest ISO footprint. Therefore any changes in production costs are directly attributable to the Midwest ISO Day-2 or No-ASM market. The actual achieved benefits are assessed as the change in system production costs between the Day-1 Case and the Day-2 Actual Case.

In each case, the system production costs comprise the fuel costs, the variable operation and maintenance costs, and the NO_X and SO_2 emission allowance charges for every generator in the US Eastern Interconnect. In the Day-2 Actual case, only Midwest ISO generators are directly observable using actual market generation data from the Midwest ISO market systems. In this case we estimate the production cost of generators external to the Midwest ISO footprint using an Interchange Index which is discussed in detail later in this chapter.

[33] Note that Midwest ISO actual operations differed significantly during the study period from the theoretical Day-2 Optimal Case modeled due to, for example, the manner in which regulation and operating reserves are currently provide in the Midwest ISO region versus the in the model representation . These differences are examined through sensitivity cases such as the "No-ASM Case".

Methodology for Assessing Day-1 and Day-2 Costs in the MAPS Framework

ICF used GE Energy's MAPS computer model for estimating the benefits associated with transforming the Midwest ISO market from a bilateral to a centrally coordinated market. MAPS is a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors from a solved power flow case to determine how power from generating plants will flow over the AC[34] transmission network[35]. This feature enables MAPS to capture the economic penalties of re-dispatching generation to satisfy transmission facility limits and security constraints. ICF used MAPS to perform a security constrained unit commitment and economic dispatch of generating resources to meet load and reserve requirements. ICF modeled a ten month historical period on a bi-hourly basis for calibration purposes (2004), and for forecasting purposes (2005 and 2006).

The outputs of the modeling exercise include power plant dispatch, hourly nodal and zonal prices, power flows on monitored transmission lines and interfaces, and a full reporting of all production costs expended within the Eastern Interconnect to meet load and reserve requirements. These costs include fuel use, emission allowance costs and variable non-fuel operation and maintenance (VOM) costs.

Model Calibration

A key element of the approach to estimating RTO benefits involves the use of "hurdle rates" to capture inefficiencies associated with decentralized markets. Two hurdles were used, a commitment hurdle and a dispatch hurdle. The analysis used commitment hurdles to capture company operation (decentralized operation) and dispatch hurdles to capture non-tariff related dispatch inefficiencies associated with scheduling and dispatching practices amongst multiple transmission providers.

A key feature of the Midwest ISO's Day-1 operation was the decentralized commitment of generation resources by individual Balancing Authorities. Unit commitment is the decision to bring a powerplant on line and make it available for dispatch at a given time and for many plants requires start-up in advance of the time when the plant would be used i.e in advance of dispatch. Under Day-1 operation, each Balancing Authority was responsible for commitment of generation to meet its load plus reserve requirements. As described earlier, hurdle rates are a modeling construct that allows us to simulate these aspects of decentralized operation by imposing an additional cost component, in most cases a significant additional cost component, on using resources outside a Balancing Authority's control. This naturally provides the economic incentive, within the modeling context, for local resources to be committed ahead of external resources, thereby simulating the Day-1 framework for unit commitment.

The determination of the appropriate level of hurdle rates is achieved through a detailed model calibration exercise in which hurdle rates are introduced in the model to calibrate the simulated model outcome to historical market outcomes. ICF calibrated to four primary parameter during this exercise, namely Midwest ISO net interchange, generation by Balancing Authorities,

[34] Alternating Current
[35] MAPS uses a linearized Direct Current (DC) Network approximation. Generation shift factors determine the amount of injected power flowing on particular transmission lines and other system elements such as transformers.

generation by unit type, and generation by unit. Since production cost models are not designed to solve for these hurdle rates, calibration exercises tend to be iterative processes whereby an initial assumption of these hurdle rates is used and refined with each successive iteration until the model outcome is reasonably close to the historical actual market outcome. Each of these parameters was calibrated to match their 2004 historical outcomes as closely as possible. The results of the calibration exercise are discussed in Chapter 4.

Without the use of commitment hurdle rates, most production cost models would assume a single region-wide market where all units are equally eligible to commit to serve the region-wide load based on economics. For example a unit in Illinois could be committed to serve load in Ohio and vice versa, to the extent it is economic to do so. The use of commitment hurdles provides the MAPS model with a means to recognize market and operational boundaries such as between the Midwest ISO and PJM as well as practices across companies operating separately within the Midwest ISO region such as Ameren, Duke Energy, and Xcel Energy. During the commitment process, these commitment hurdles ensure that only company resources are committed to meet company load first before being made available to meet the needs of other interconnected companies.

The Project Steering Committee in consultation with the Midwest ISO selected 2004 as the appropriate year to calibrate the model for this study. Therefore, ICF used April – December 2004 market data provided by the Midwest ISO and Stakeholders for this calibration exercise. Exhibit 2-1 provides a high level overview of the data used for the calibration and the associated sources.

Exhibit 2-1:
Summary of Calibration Data

Parameter	Source
2004 Hourly Demand	Midwest ISO
Existing Generator Cost and Performance	Stakeholders
Existing Generator Interconnection Nodes	Midwest ISO
Operating Reserve Requirements	Regional Reliability Organizations
Existing Transmission Network	Midwest ISO
Transmission Access Rates	Midwest ISO
"Must-Take" Contracts	Stakeholders
Voltage Support Facilities	Stakeholders
Coal Prices (2004)	SNL Financial
Natural Gas Prices (2004)	Gas Daily
Oil Prices (2004)	Bloomberg
SO_2 and NO_X Allowance Prices	Air Daily
2004 Actual Unit Generation (MWh)	Platt's and SNL Financial

The commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provides information to guide refinement of the commitment or dispatch hurdles, or both. Specifically, for each unit within the Midwest ISO, the model determines hourly whether the unit should be committed and dispatched. This is done through a multi-pass commitment process that performs hourly commitment of resources to serve load while simultaneously looking one week ahead.[36] Thus the total number of hours the

[36] The forward looking view ensures that each unit's operating characteristics such as minimum uptime and downtime are not violated.

unit is committed and dispatched (and associated generation) can be imputed for the year. Note that in the model, a unit that is not committed will not dispatch; consequently, the level of commitment (in hours) will always be greater than or equal to the level of dispatch. Through the iterative calibration process, the model's projections for unit commitment and dispatch were compared to actual historical operation, especially for units that showed large deviations, to determine the appropriate hurdle rate adjustments. For example, if a unit that historically dispatched in 2004 did not dispatch as much in the 2004 calibration model and also did not commit as much as would be required to permit the level of historical dispatch, then the commitment hurdle was adjusted. In contrast, if the unit was committed as expected, but did not dispatch as much as it actually did historically, then the dispatch hurdles were adjusted.

Modeling Treatment across Cases

A large number of parameters were treated consistently across all the cases. These include basic supply/demand fundamentals such as demand levels, physical supply characteristics, fuel prices, environmental allowance prices, etc. Additionally, any transmission or generation capacity expansion was modeled consistently across all cases, as was the treatment of must-run/must-take contracts.

There were, however, key structural and operational parameters that were modeled differently across the cases to capture the alternative simulated market structures. Exhibit 2-2 summarizes the treatment of key parameters in the modeling of the cases and the major differences across cases from a modeling perspective. These major areas of differences are captured through the treatment of:

- Unit commitment and dispatch;
- Transmission rates;
- Operating reserves; and
- Utilization of existing transmission assets.

Exhibit 2-2:
Summary of Key Differences Across Reference Cases

Parameter	Day-1 Case	No-ASM Case	Day-2 Optimal Case
Security Constrained Unit Commitment (SCUC)	Commit to meet Balancing Authority load plus reserve	Midwest ISO region-wide centralized commitment	
Security Constrained Economic Dispatch (SCED)	Dispatch to meet Balancing Authority load plus economy interchange;	Midwest ISO region-wide centralized dispatch	
Hurdle Rates	H1 – Hurdle designed in model to force unit commitment by Balancing Authority – Applicable only to unit commitment (SCUC) – does not directly affect SCED	None	
	H2 – Realized hurdles from model calibration exercise to capture non-tariff related dispatch inefficiencies		
Transmission Tariffs	Midwest ISO-wide uniform tariff		
Transmission Limits	Reduced actual line limit based on prior Midwest ISO analysis of historical data	100 percent of the actual line limit	
Operating and Regulation Reserves	Based on existing Midwest ISO Operating Reserve requirement. Each Balancing Authority provides operating reserves based on their allocation under the Reserve Sharing Agreement		Based on centralized footprint-wide operating reserve market

Unit Commitment and Dispatch

The Day-1 Case model was configured to permit each company to commit its resources to serve native load. This was achieved by the use of hurdle rates designed to constrain each Balancing Authority's generation resources to serving its load first. In addition, ICF used small, uniform, dispatch hurdle rates to capture non-tariff related Day-1 market inefficiencies associated with Balancing Authority operations.

The application of the commitment hurdles was evaluated carefully to ensure that the desired effect was achieved i.e., for each company or Balancing Authority least cost units were committed before the more expensive units. In many of the models used for cost benefit analyses, such as MAPS, the commitment decision for a generation unit is based on its priority cost. The lowest priority cost generation resource within a Balancing Authority or within a company's fleet of resources gets committed first to serve its load. In turn, each unit's priority cost is determined by two key components:

- its variable costs, [37] and
- its natural location factor[38] with respect to transmission constraints and losses.

[37] The variable cost components of each unit's priority costs include fuel, variable operation and maintenance cost, start-up costs and emissions cost.

When commitment hurdles are introduced in the model as a means to simulate a decentralized market, a third component is introduced to the priority cost equation. This third component, if not properly applied, can introduce distortions to the resultant unit commitment stack. Since the commitment hurdle is designed to constrain a group of generation resources available within a Balancing Authority or belonging to a company to serve its load, appropriate care should be taken to ensure that the impact of the commitment hurdle is uniform across that target group of resources. These commitment hurdles, if applied across Balancing Authority tie-lines, can introduce locational biases to the target resources and the effect would be a non-uniform impact of the commitment hurdle across the target resources. For example, assume a particular Balancing Authority has a single tie with its external electrical world. If a $20/MWh commitment hurdle is placed at this tie, then the impact of the commitment hurdle on each of the units within that particular Balancing Authority will depend on each unit's shift factor across that tie. Thus, if two units in that Balancing Authority have different shift factors across this tie, the impact of the commitment hurdle will not be uniform and may distort the priority costs of both units. Thus, an improper application of the commitment hurdle may have the unintended consequence of committing the more expensive generation resource before the cheaper generation resource.

To avoid this problem, ICF did not apply the commitment hurdles at the Balancing Authority ties. Instead, ICF used special operating nomograms to uniformly apply the commitment hurdle to each company's units to achieve the dual objectives of:

- Constraining units within the company/Balancing Authority to commit to the Balancing Authority/company load first before committing to some other load;
- Ensuring that units within each Balancing Authority/company maintain their true commitment priority derived from their variable costs and their natural location factors.

Modeling of Transmission Facility Limits and Flowgate Utilization

ICF has explicitly modeled all designated NERC and Midwest ISO flowgates[39] in this analysis. Flowgates are usually the sensitive and often stressed locations in the grid. Transmission flowgates are frequently monitored for potential line overloads should there be contingency and/or emergency conditions such as outage of line(s) or generation plant(s) or both. Approximately 1300 NERC flowgates, 100 Midwest ISO flowgates and 10 rule-based limits (nomograms) were modeled with explicit monthly limits for this analysis.

Although flowgate limits vary on an hourly basis, such variability is not practical to include in a market simulation model. ICF in consultation with the Steering Committee determined that inclusion of monthly limits in the model would be adequate for this analysis. For Day-1 modeling, every flowgate limit was reduced by a certain percentage (see Exhibit 3-21) based on actual flowgate utilization during level-3 and higher TLR events. This assumption is based on analysis performed by the Midwest ISO and documented in a memorandum distributed to the study stakeholder group. The decision to utilize a single flow gate limit for every hour of the

[38] The natural location factor of a generation unit is a measure of its locational advantage or disadvantage with respect to constraints within the transmission system. It is represented by a matrix of the unit's shift factor on all transmission system elements with respect to a designated Reference location on the grid. Thus, all units have their matrix of shift factors. These shift factors change with a change in the Reference Location and/or a change in the grid topology.

[39] NERC defines certain transmission lines or paths through which power flow from power transactions are calculated during system operation. These are typically lines or paths that could get congested and impact power transactions. These points are called flowgates.

month means that in some hours the actual flow gate limit was greater than simulated whereas in other hours the actual flow gate limit was less than simulated. The larger the gap between actual and simulated flow gate limit the greater the error in the simulation result for that hour relative to what actually occurred. Assuming more or less equal distribution of "over" and "under" hours, the average effect should not greatly impact the analytic results.

Treatment of Operating Reserves

ICF modeled operating reserves based on the operating reserve requirement within the Midwest ISO market. This Midwest ISO reserve requirement mandates a total of 3,655 MW[40] of operating reserves for the Midwest ISO region.

In the Day-1 and No-ASM Cases the treatment of operating reserves was consistent with the actual Midwest ISO's operation. Operating reserves are largely decentralized and held locally by the Balancing Authorities. Each Balancing Authority is responsible for meeting its share of the Midwest ISO operating reserve requirement.

One of the benefits of Day-2 market operation is efficiency gains resulting from a centralized provision of regulation and operating reserves. The modeling of regulation and operating reserves in the Day-2 Optimal Case reflected a centralized regulation and operating reserve market. Regulation and operating reserves were held at the Midwest ISO level, and the most economical generation resources were committed and dispatched to meet demand and required regulation and operating reserves on a region-wide basis. This approach determined the maximum theoretical benefits achievable from Day-2 operation of the Midwest market including both energy and ancillary services.

The Midwest ISO, however, did not operate a centralized ancillary services market in its implementation of Day-2 operation during the study period. Regulation and operating reserves were still decentralized and held locally by the Balancing Authorities similar to Day-1 operation. The No-ASM Case was designed to evaluate the impact of this variation in implementation on the overall benefits of the Day-2 operation. Therefore, in the No-ASM Case the majority[41] of regulation and operating reserves were held locally at the Balancing Authority level. This approach determined the achievable benefits from the Midwest ISO's implementation of the Day-2 market.

Treatment of Losses

MAPS is capable of modeling the primary methodologies currently used in power markets to capture the effect of losses on the operation of the grid, namely average and marginal losses. In its Day-1 market, the Midwest ISO used average loss implementation. This framework assumes that losses are proportional to power produced, and losses are allocated to market participants based on a pro-rata share of total transmission losses. This treatment is consistent with the Midwest ISO's closest neighbors PJM[42] and SPP. In its Day-2 market, the Midwest ISO implemented marginal losses, similar to the New York ISO and the New England ISO. Under the marginal loss approach, transactions are assessed charges for losses based on their

[40] See Chapter Three for a detailed accounting of the components of this reserve assumption.
[41] Headroom reserves equal to 700 MW are assumed to be held by the Midwest ISO in this case.
[42] Note that PJM intends to implement a marginal loss regime in June 2007.

incremental impact on system losses, which accounts for the locational impact of injections on system losses.

The MAPS model treats losses uniformly system-wide. Since ICF modeled the entire Eastern Interconnect, the implementation of losses selected for a particular case applied system-wide. For example, if average losses were selected for the Midwest ISO Day-1, MAPS would assume average losses for the entire Eastern Interconnect in the model. Given this limitation and the fact that most of the Eastern Interconnect operates under average rather than marginal losses, ICF chose to model average losses for the entire system in all cases since this would introduce the least bias to the model results.

Methodology for Assessing Day-2 Actual Costs

To calculate the estimated benefits achieved by the Midwest ISO over the ten month study period, ICF utilized the actual hourly generation data provided by Midwest ISO from Day-2 market operations to develop the Day-2 Actual Case. Estimated production costs were computed from this data by multiplying the actual generation in MWh by an estimated average cost per MWh for each generating unit. The results of this calculation were compared against model derived production cost estimates for the Day-1, Day-2 Optimal, and No-ASM cases in order to develop the estimated benefits achieved. The key to this effort was calculating an estimated production cost for the actual operation that would be consistent with our simulated MAPS production cost estimates for the comparison cases. This consistency is achieved by estimating actual production cost using actual generation and model-based production costs. Any difference between actual offers and model-assumed production cost may introduce error into the comparison of actual and hypothetical achievable benefits. Thus, although this technique is required to develop a meaningful comparison of production cost between the hypothetical and actual cases, the resulting inconsistency between the actual dispatch (based on actual offers) and hypothetical dispatch (based on assumed offers) introduces a difficult to quantify error in the estimated study result. Estimating the size of this error is not within the scope of this analysis.

Day-2 Actual Approach

The production costs savings for the Day-2 Optimal Case is defined as the total system production costs for the Day-1 Case ($) less the total system production costs for the Day-2 Optimal Case. In this analysis, the “total system” is defined as the US Eastern Interconnect. We include this wide scope in our modeling to account for all market participant responses to the change in the Midwest ISO market structure. That is, in our modeling framework both Midwest ISO market participants and non-Midwest ISO market participants may respond to the changes occurring in the Midwest ISO market structure in order to minimize their operating costs. This adds to the scope of the analysis, but this expansion is necessary.

There are two broad production cost components that are considered in estimating the total system production costs. Namely, 1) costs from local generation and 2) costs from generation outside the Midwest ISO footprint. In the Day-1, Day-2 Optimal, and No-ASM Cases both of these values are direct outputs of the ICF modeling exercise.

In the Day-2 Actual Case, the comparison to Day-1 system production costs is not directly possible because we can only directly measure production costs within the Midwest ISO given the actual hourly data available for generation from units within the Midwest ISO market footprint. For example, we do not have access to a consistent set of hourly generation, unit cost and performance, and actual fuel cost data for facilities in PJM, SPP, or other regions.

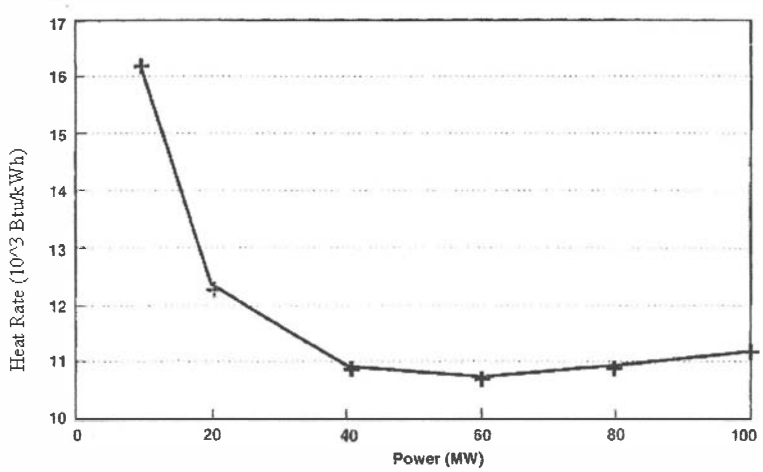
We discuss the approach used to estimate each of these two cost components for the Day-2 Actual Case below.

Costs from Local Generation

Each local generation unit has four main sub-components of costs associated with generation dispatch. These costs are fuel, non-fuel variable operating and maintenance costs (VOM), NO_X emission costs and SO_2 emission costs. The approach used to capture costs for each sub-component is described below.

Fuel Cost: The cost of fuel used by each local generator is calculated for every unit in the Midwest ISO for every hour by multiplying fuel used (MMBtu) by the fuel price ($/MMBtu). The fuel used is calculated by mapping the unit's actual hourly dispatch in MWh to the estimated instantaneous heat rate of that unit based on the unit's output/heat rate curve used in the MAPS model. See sample heat rate curve below.

Exhibit 2-3:
Illustrative Heat Rate Curve of a Unit in the MAPS Model



Source: ICF

The heat rate (Btu/kWh), in conjunction with the hourly unit output (MWh), provides the quantity of fuel used in MMBtu for that hour. This quantity is then multiplied by the monthly average fuel price ($/mmBtu) to calculate a total fuel cost for each unit in each hour. For example a CT with an instantaneous heat rate of 10,000 Btu/kWh at the 30 MW set point in a given hour will realize a fuel cost of $1,800 per hour as shown below:

*$6.00/MMBtu * 10,000 Btu/kWh / 1000 * 30 MW = $1,800/hr in fuel costs*

VOM Cost: Non-fuel VOM costs are calculated by multiplying the stakeholder-provided VOM costs ($/MWh) by total unit output (MWh). For example a CT with a VOM of $4/MWh generating 30 MW in a given hour will realize VOM cost of $120 per hour. See calculation below:

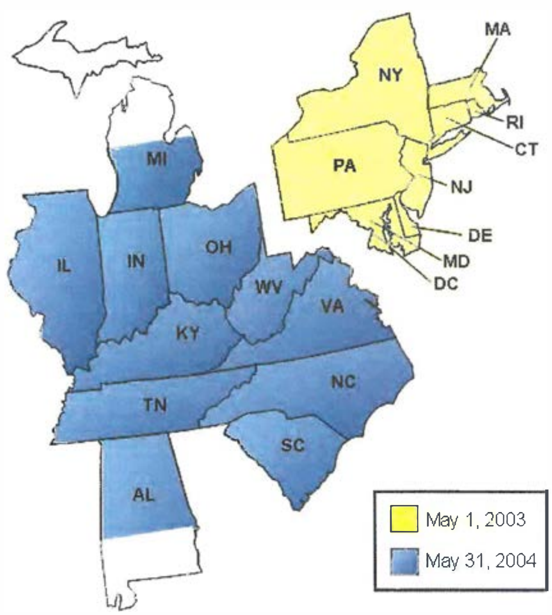
*$4.00/MWh * 30 MW = $120/hr in VOM costs*

NO_X Allowance Costs: Emissions cost associated with the consumption of NO_X allowances are calculated by multiplying the NO_X output (tons) by the monthly average allowance price ($/ton). The total NOx pollutant output is derived from fuel used (MMBtu) by the unit and the unit's emission rate (lb/MMBtu) as provided by Stakeholders and confirmed with data from SNL Financial. Note that NOx costs are calculated for SIP[43] Call affected units in summer months only. For example, a CT with a 10,000 Btu/kWh heat rate, generating 30 MWs in a given hour with an emission rate of 0.1 lbs/MMBtu will realize a NOx emission costs of $45 per hour as shown below if we assume an allowance price of $3,000/ton:

*10,000 Btu/kWh * 30,000 kWh / 10e6 * 0.1 lb/MMBtu / 2,000 lb/ton * 3000$/ton = $45/hr*

Note that the SIP Call policy is a regional emissions policy covering only a portion of the Midwest ISO footprint. Exhibit 2-4 below highlights the state by state coverage of the SIP Call program.

Exhibit 2-4:
NOX SIP Call States



Source: ICF

[43] State Implementation Plan.

SO_2 Allowance Costs: Similarly, SO_2 allowance costs are calculated by multiplying SO_2 output (tons) by the monthly average allowance price ($/ton). The SO_2 output is derived from fuel used (MMBtu) by the unit and the unit's emission rate (lb/MMBtu). The emission rate is calculated from the pollutant content of the fuel burned (lb/MMBtu), and any applicable emission reductions (%) resulting from installed SO_2 scrubbers – i.e. from flue gas desulfurization equipment.

For example, a conventional coal unit with a heat rate of 9,000 Btu/kWh generating 300 MWs in a given hour with an emission rate of 1.0lbs/MMBtu will realize the SO_2 emission costs below:

*9,000 Btu/kWh * 300,000 kWh / 10e6 * 1.0 lb/MMBtu / 2000 lb/ton * $700/ton = $945*

Non-Midwest ISO Unit Production Costs

To maintain consistency with the production cost framework of the model, we have assumed that the Non-Midwest ISO region unit production costs are consistent with model costs realized in the Day-2 Optimal Case adjusted for any changes in Midwest ISO net interchange with neighboring regions on a monthly basis. Total production costs for all generators outside of the Midwest ISO are comprised of hourly production costs related to fuel, VOM, NO_X and SO_2 expenses. These costs are aggregated to a monthly total and adjusted to account for any differences in net interchange in that month between simulated Day-2 Optimal model results and actual operations. For example, if net interchange results indicated fewer imports in the Day-2 Optimal case than actual operations, an import adder was added to ensure that production costs in the Day-2 Actual Case included costs associated with the correct number of megawatt hours. In this example the import adder would be the product of the change in imports (MWh) times the average production costs realized outside of the Midwest ISO footprint for that month in the Day-2 Optimal Case. We believe that this is an appropriate treatment on external production costs and note that the "import adder" accounts for less that 0.08 percent of the Day-2 Actual production cost estimate over the ten month period.

Note that generation from hydroelectric facilities, wind facilities and from Canadian imports were not included for production cost purposes as these units are set to match historical generating patterns and do not vary their operation across cases considered. In other words, the Day-1, Day-2 Optimal, No-ASM, and Day-2 Actual Cases all include the same generation pattern for these units on an hourly basis.

Stakeholder Participation Process

This study was driven by an open and interactive Stakeholder process designed to ensure the accurate representation of the Midwest ISO system and to benefit from the feedback of all Stakeholders. A Project Steering Committee comprising key Midwest ISO personnel provided guidance and administration in providing ICF with the relevant data and coordinating the gathering of Stakeholder data. This ensured an efficient process of data transfer and data verification.

Although the scope of the study was developed and approved by the Midwest ISO, it was done in consultation with other Stakeholders, including municipal utilities, cooperative utilities, and