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Independent Assessment of Midwest ISO Operational Benefits

Submitted to:
Midwest ISO

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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".

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

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.

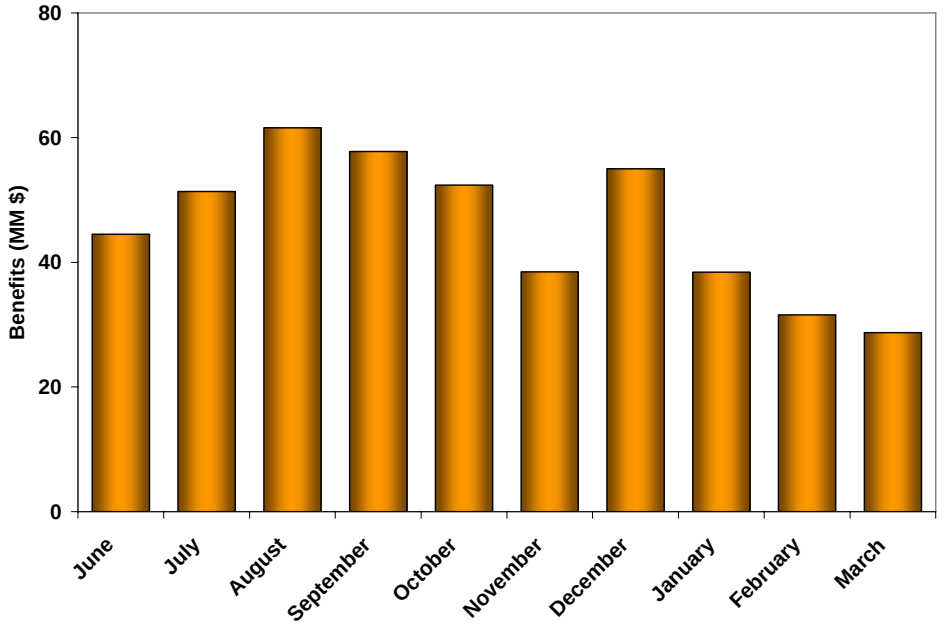
In each of the three cases the system production costs comprise the hourly fuel, variable operation and maintainence, NO_x emission allowance, and SO_2 emission allowance costs of every generator in the US Eastern Interconnect[8].

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.

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

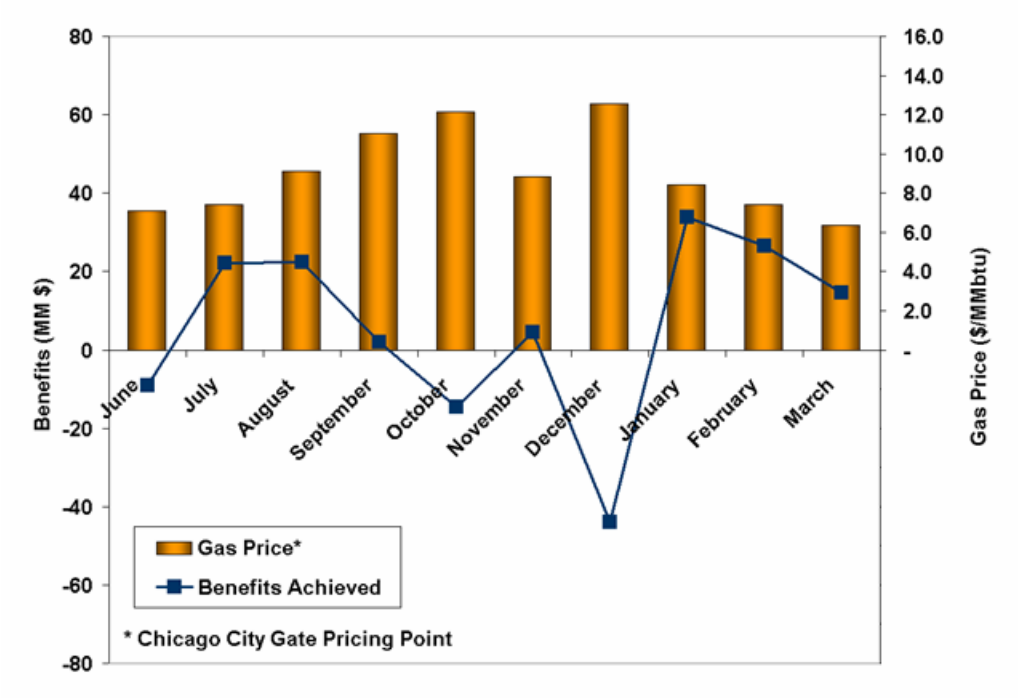
Our analysis yields the following three primary results:

- 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.

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:

- 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.

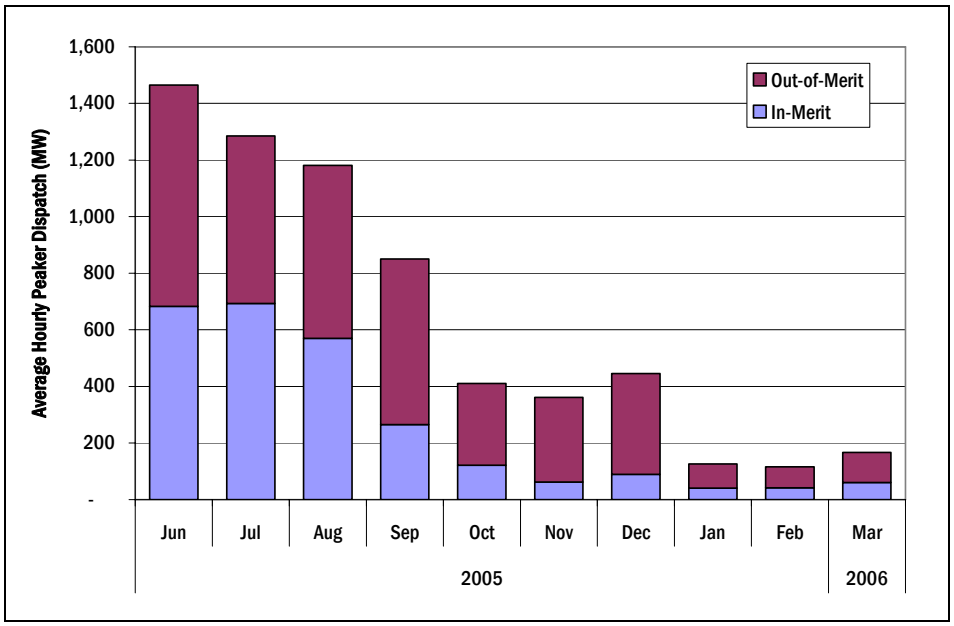
[10] Source: Gas Daily; Chicago City Gate price

[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.

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.

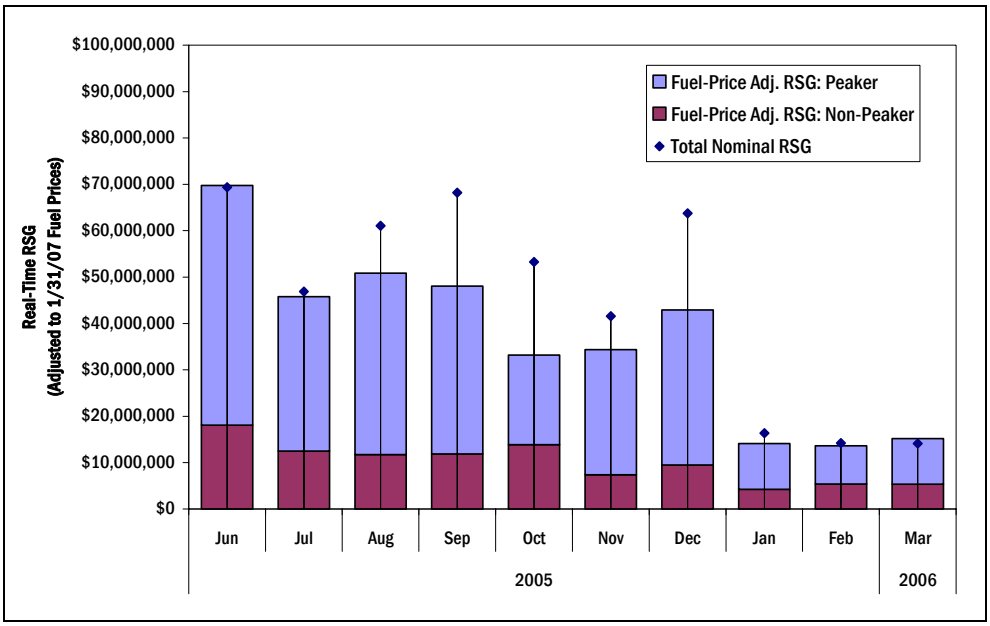
Exhibit ES-6:
Market Monitor Analysis of the Dispatch of Peaking Resources



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.

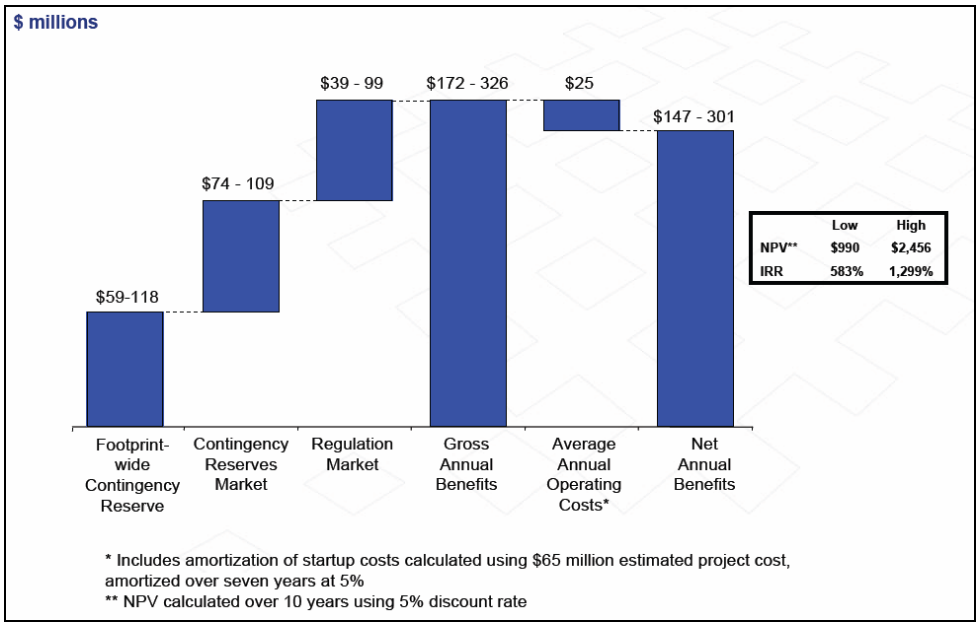
Exhibit ES-7:
Market Monitor Analysis of the Midwest ISO RSG Payments



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



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

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.

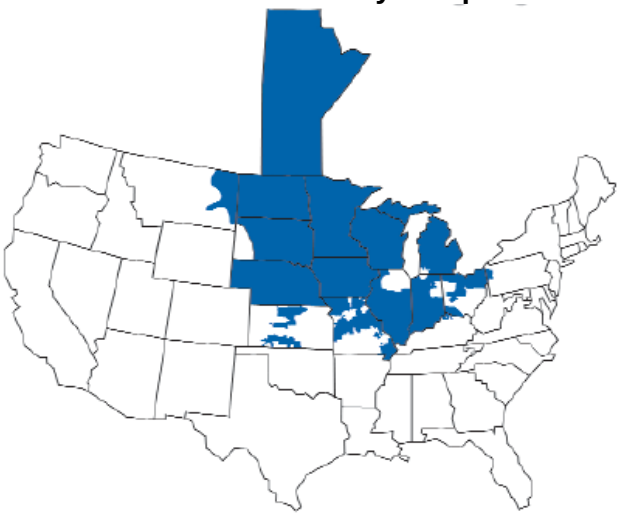
Regional Overview of the Midwest ISO[12]

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.

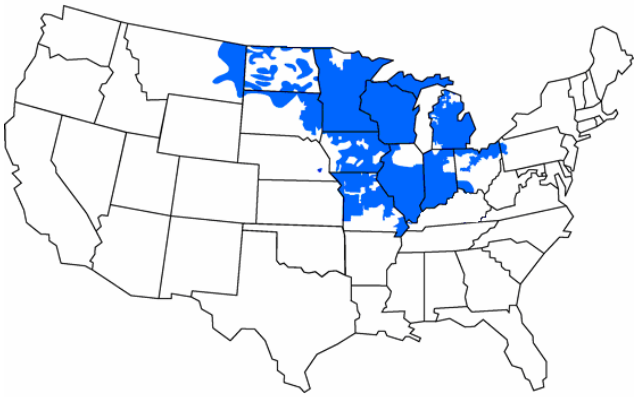
[12] From the Midwest ISO website unless otherwise noted.

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.

Exhibit 1-3:
Midwest ISO Overview

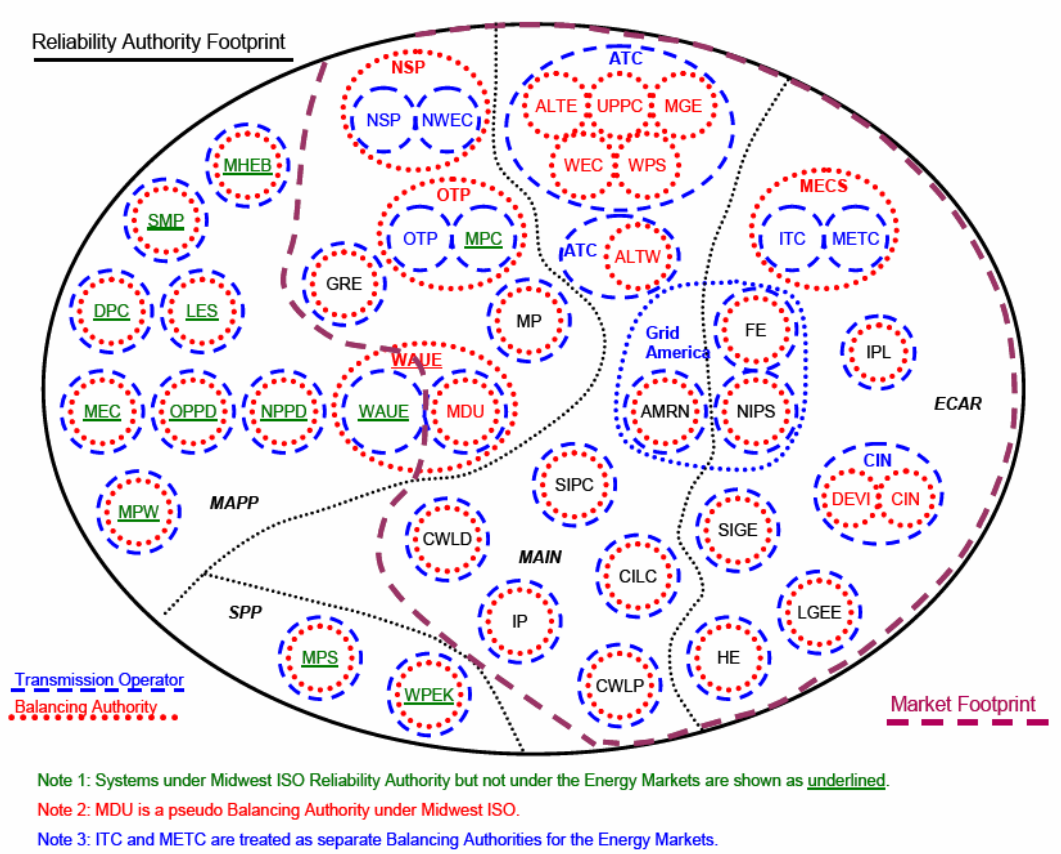
Metric	Parameter
Territory	920,000 square miles covering 15 US states and Canadian province of Manitoba. Control centers in Carmel, IN and St. Paul, MN
Market Participants	256 including 28 Transmission Owners with $13.9 billion in transmission assets under the Midwest ISO's functional control and 69 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.

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



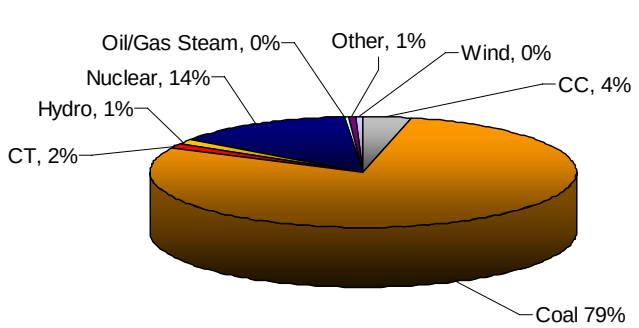
Source: Midwest ISO Business Practices Manual for Coordinated Reliability, Dispatch, & Control, Manual No. 006, 2005. Note that GridAmerica and ATC are no longer operational but the Balancing Authorities pictured are valid up to the end of the study period in March 2006. Since then, DEVI and LGEE are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

Midwest ISO Supply Mix

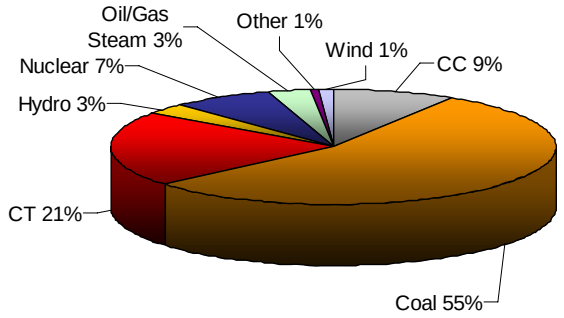
The Midwest ISO is one of the largest markets in the US with a net internal peak demand over 116 GW[14] and has a bimodal winter and summer peaking profile. Exhibit 1-5 shows the percentage breakdown of dispatch and capacity by generation source for the study horizon from June 2005 through to March 2006. 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.

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.

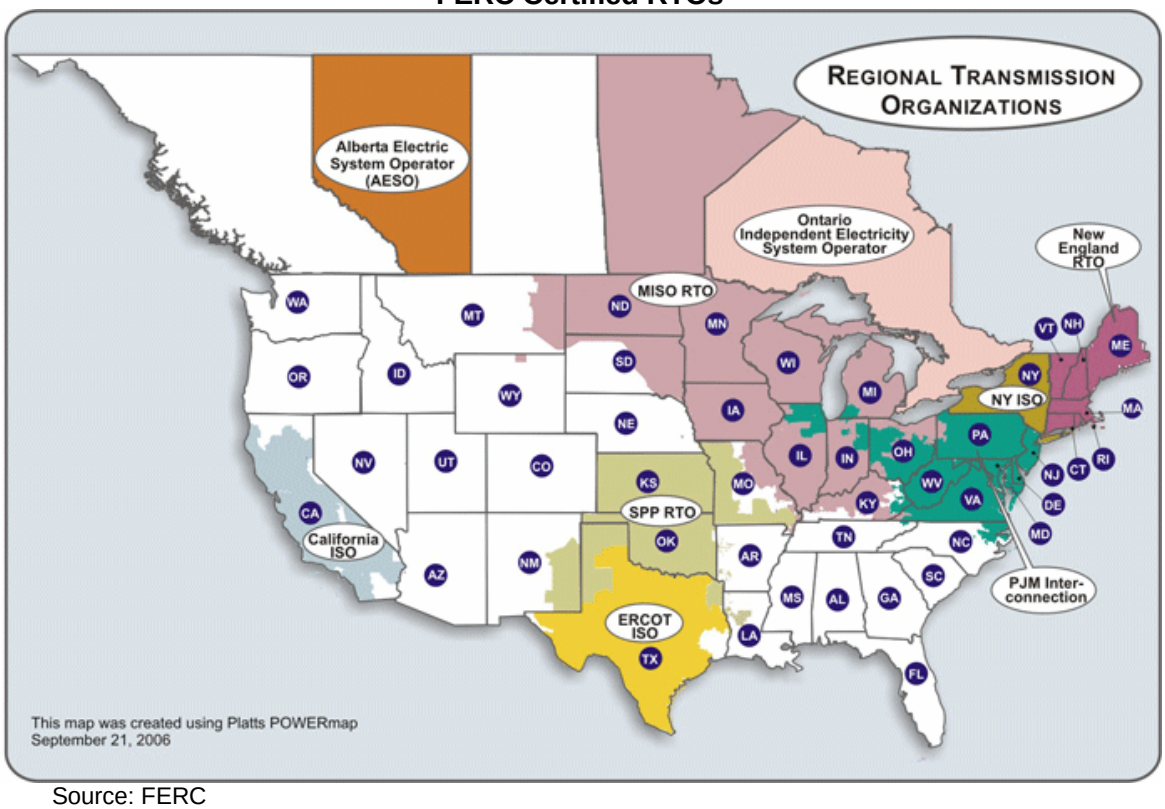
Midwest ISO's Interconnectivity with the Rest of the Grid

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

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

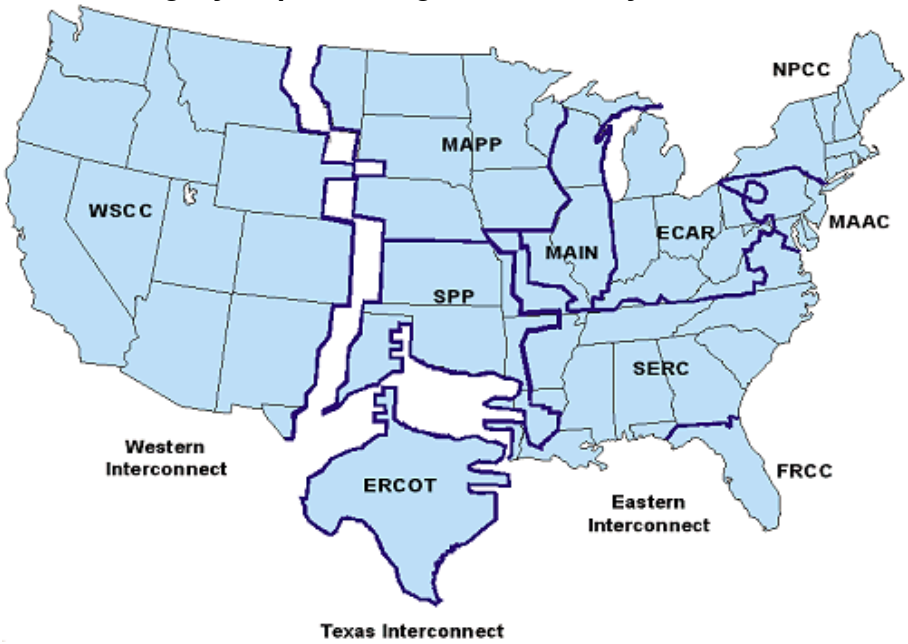
In 2002 the FERC directed the Midwest ISO and PJM to work toward development of a common market by October 1, 2004 in order to harmonize their practices to functionally create a single, transparent energy market.[17] The creation of a "joint and common" market for PJM and the Midwest ISO goes well beyond 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.

[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.

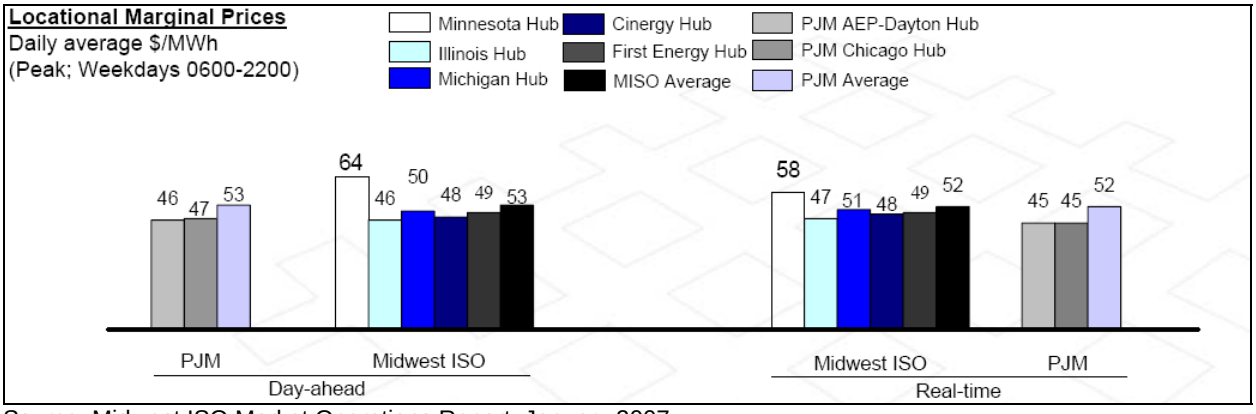
The Midwest ISO publishes a day-ahead schedule and a 24-hour day-ahead set of LMPs. The day-ahead schedules constitute financial contracts to supply or consume power. FTRs are also settled based upon the 24-hour day-ahead LMP values.

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

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).

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

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

[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.

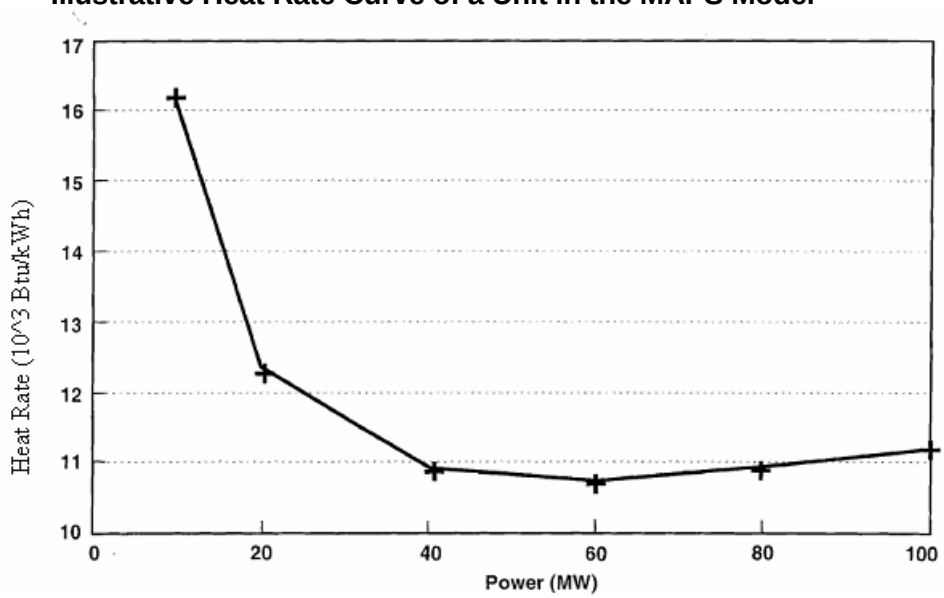
We discuss the approach used to estimate each of these two cost components for the Day-2 Actual Case below.

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:

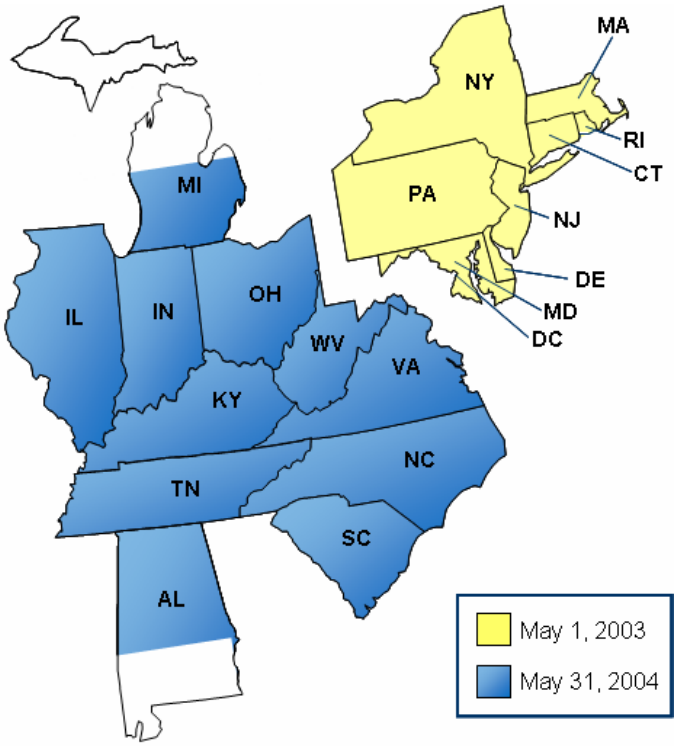
*$4.00/MWh * 30 MW = $120/hr in VOM costs*

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

independent power producers active in the Midwest ISO market. The following outline details the steps taken by ICF to ensure Stakeholder participation:

- **Establishing an open channel of communication** - ICF created a secure website to register all Stakeholders (see Exhibit 2-5). This electronic format has proven to be extremely efficient in communicating any updates and changes to a large group of participants. It also served as an open forum for each Stakeholder to address concerns or make corrections as well as a central drop off point for uploading and downloading documents. There were a total of 94 registered participants from 56 organizations ranging from utilities to independent power producers to local utility commissions. This website is in addition to traditional channels of communication such as conference calls, emails, written communication, etc.

Exhibit 2-5:
Stakeholder Information Website

Source: ICF

- **Sharing information** – In order to ensure that all Stakeholders were aware of the parameters of the study, ICF distributed a 200 page document detailing the proposed assumptions and methodology. The website was used as the central distribution point.

- **Ensuring an inclusive and interactive process** – After all the Stakeholders received the methodology and assumptions document, ICF opened a review and comment period. Stakeholders submitted comments or questions on the established website to assure their concerns and comments were visible to all parties. In all, 91 comments were received and ICF replied to all of them either

clarifying certain points or, where appropriate, making model adjustments. The website was used as the central distribution point for ICF responses.

- **Face-to-face Meetings** – ICF held a Stakeholder meeting in late February 2006. ICF and the Midwest ISO used this venue to introduce stakeholders to the study scope, goals, and the general study approach.
- **Verifying Data** - ICF initially received much of the model input data directly from the Midwest ISO. However, to verify this data, ICF entered into confidentiality agreements with individual Stakeholders, who then reviewed and commented upon generation resource thermal and cost data used for modeling. This ensured that the results of our analysis reflect as accurately as possible the actual condition of the Midwest ISO market during the study period. In all, Stakeholders accounting for 80 percent of installed capacity reviewed detailed assumptions data for their facilities. Data items reviewed included:
    - Plant Name and Unit Number
    - Ownership share
    - Balancing Authority Name
    - CPNode Name
    - Interconnection Node Name
    - Online Date
    - Retirement Date
    - Unit Type/Prime Mover
    - Maximum Summer/Winter Capacity (MW)
    - Primary/Secondary Fuel
    - 2004/2005/2006 Average Fuel Cost($/MMbtu)
    - Minimum Runtime/Downtime (Hrs)
    - Ramp Up/Down Rate (MW/hr)
    - Average Full Load Heat Rate (Btu/Kwh)
    - Variable O&M ($/MWh)
    - Start Up Cost ($000)
    - Must run status

Through this iterative and open process, ICF was able to assure a high degree of model input data accuracy, enhancing the model representation and hence the evaluation of the theoretical maximum, achievable, and actual achieved benefits available to Midwest ISO market participants as a result of the Midwest ISO Day-2 market.

CHAPTER THREE:
OVERVIEW OF MODELING ASSUMPTIONS

Chapter Three presents an overview of the modeling assumptions used by ICF in this analysis. This chapter is broadly broken into three parts (1) Supply Side Assumptions (2) Demand Assumptions and (3) Transmission Assumptions. This study was driven by a multi-faceted and interactive Stakeholder process designed to ensure the accurate representation of the Midwest ISO system and to benefit from the feedback of all Stakeholders. The Midwest ISO and its stakeholders provided the majority of the study assumptions. The table below lists the major data elements and their sources.

Exhibit 3-1:
Data and Source for Modeling Assumptions

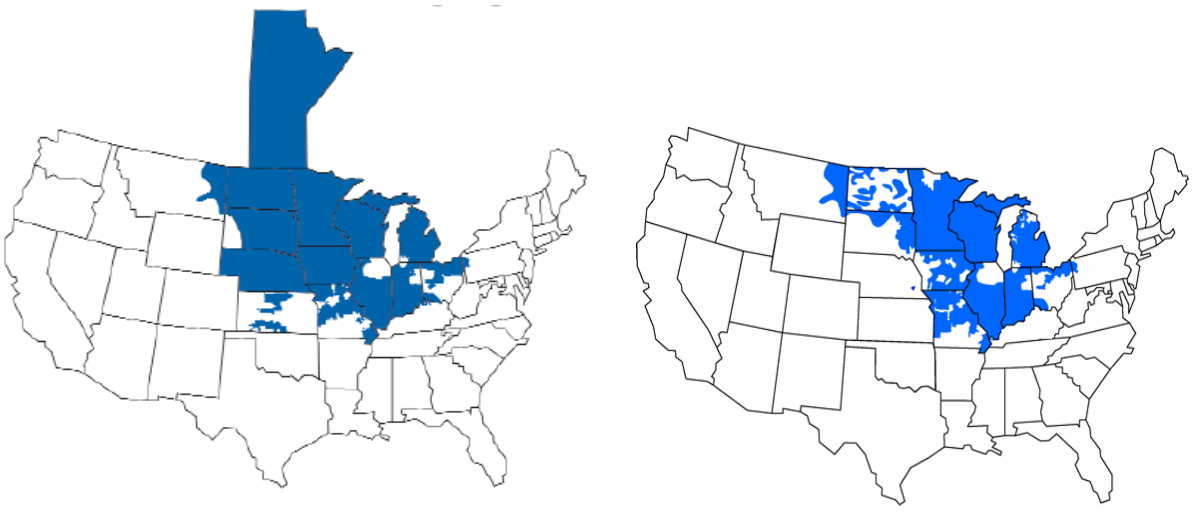
Data Element	Source
Unit heat rates	Stakeholders/Midwest ISO
Unit primary fuel	Stakeholders/Midwest ISO
Unit secondary fuel	Stakeholders/Midwest ISO
Unit ramp rates	Stakeholders/Midwest ISO
Unit NOx emission rates	Stakeholders/Midwest ISO/ICF
Unit interconnection nodes	Stakeholders/Midwest ISO
Must-run requirements	Stakeholders/Midwest ISO
Hourly unit dispatch (2004,2005 and 2006)	Midwest ISO
Zonal Definitions	Midwest ISO
Hourly Demand by Zone (2004, 2005 and 2006)	Midwest ISO
Midwest ISO internal and external interfaces and flowgates	Midwest ISO
Tariff detail; firm and non-firm 2004	Midwest ISO
Hourly Imports from Canada	Midwest ISO
Power flow cases	Midwest ISO
Spinning reserve requirements	Midwest ISO
Fuel prices	ICF; based on historical data
Midwest ISO Members	Midwest ISO
Emissions costs	ICF; based on historical data

For all cases analyzed, the Midwest ISO was modeled as an integrated system within the larger Eastern Interconnect. ICF assumptions were used for the rest of the eastern interconnect wherever historical data was not available. Exhibit 3-2 compares the geographic reliability and market footprints for the Midwest ISO while Exhibit 3-3 shows a schematic representation of the Balancing Authorities in these footprints. For this analysis, ICF focused on the 26 Balancing Authorities within the Midwest ISO market footprint. These 26[44] Balancing Authorities were modeled as separate markets in Day-1 for the purpose of unit commitment and operating reserves. In the Day-2 Optimal Case simulation, unit commitment and operating reserves was performed on a Midwest ISO-wide basis.

[44] DEVI and CIN are aggregated in this analysis

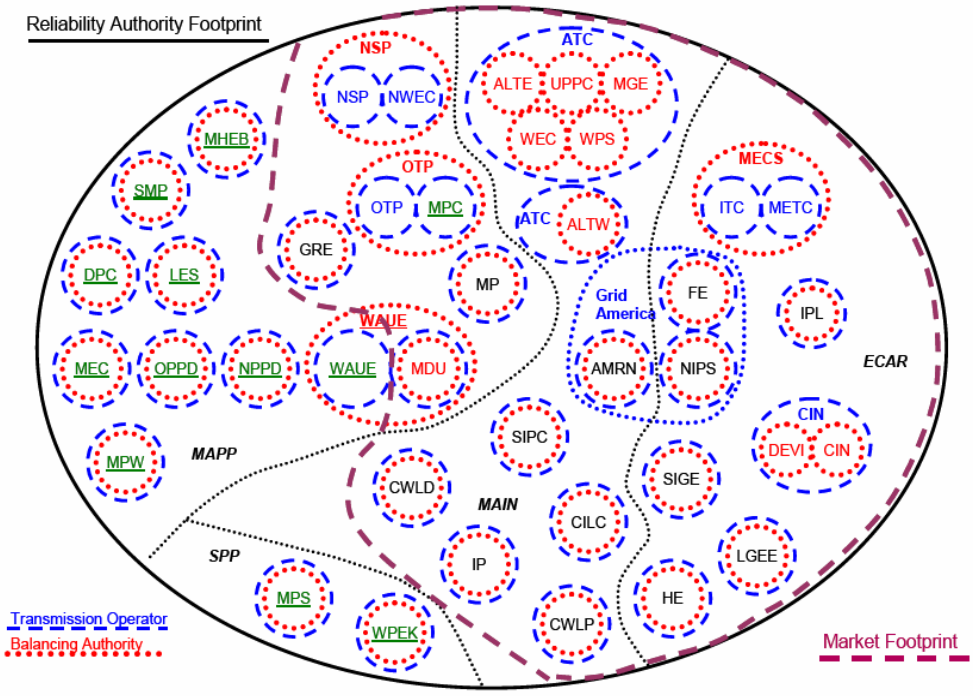
Exhibit 3-2:
The Midwest ISO Reliability and Market Footprints

Reliability Footprint **Market Footprint**



Source: Midwest ISO

Exhibit 3-3:
The Midwest ISO Balancing Authorities in the Reliability and Market Footprints



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. See Demand Section below for acronym definitions. 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 (as of 6/2006 and 9/2006, respectively) and SMP has joined the market footprint (as of 4/2006).

Supply-Side Assumptions

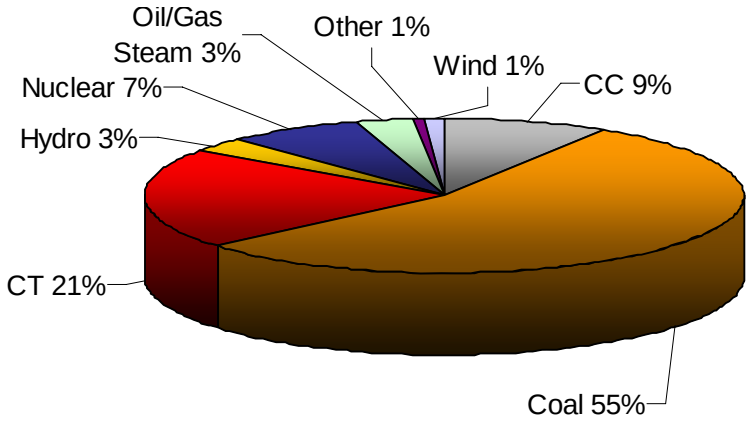
This section focuses on the key supply-side assumptions underlying the analysis. These include the following 5 broad categories:

- Existing Capacity;
- New Builds;
- Fuel Prices (natural gas, coal, oil);
- Environmental Compliance and Allowance Prices; and
- Existing Unit Characteristics (Heat Rates, VOM, Ramp-up rates etc)

Existing Capacity

The Midwest ISO capacity mix is dominated by base load generation in the form of coal and nuclear plants as shown in Exhibit 3-4. These units together comprise 62 percent of the Midwest ISO supply mix. When compared to other areas of the US the Midwest ISO is characterized as having relatively more baseload generation and little in the way of intermediate generation resources such as combined cycle. In the study period, we see that combined cycle units comprise only 9 percent of the capacity mix while units traditionally used for peak periods such as oil/gas steam and combustion turbine capacity accounted for a total of 24 percent of the mix. Thus, while the Midwest ISO is characterized as heavily baseload, during peak periods the area relies extensively on gas-fired peaking units with higher marginal costs.

Exhibit 3-4:
The Midwest ISO Capacity Mix, June 2005 through March 2006



Total Installed Capacity: 138 GW[45]

Source: Midwest ISO

[45] Midwest ISO total installed capacity by capacity type as of March 2006.

New Builds

From April 2004 to March 2006, a total of approximately 6.4 GW of new capacity came on-line within the Midwest ISO footprint. As noted earlier, the Midwest ISO has been increasing its reliance on natural gas-fired generation in recent years. This is evidenced by the fact that approximately 80 percent of the new capacity that came online during the study period was gas-fired, and virtually none was coal-fired. Indeed, in one case (Port Washington), the new gas plant was effectively replacing an older coal-fired powerplant.

Exhibit 3-5:
Midwest ISO Capacity Mix

Unit Name	Balancing Authority	Unit Type	Online Date	Capacity (MW)
Emery Generating Station	ALTW	Combined Cycle	5/18/2004	570
Riverside Energy Center	ALTE	Combined Cycle	6/1/2004	602
Trimble County	LGEE	Combustion Turbine	6/25/2004	600
West Campus Cogeneration Facility	MGE	Combined Cycle	4/26/2005	168
Angus Anson 3	NSP	Combustion Turbine	6/1/2005	160
Blue Lake 6 & 7	NSP	Combustion Turbine	6/1/2005	320
Sheboygan Falls	ALTE	Combustion Turbine	6/2/2005	350
Fox Energy Center (Kaukauna)	WPS	Combined Cycle	6/6/2005	550
Venice (AUEP)	AMRN	Combustion Turbine	6/10/2005	400
Port Washington	WEC	Combined Cycle	7/16/2005	545
Northome Wood Plant	MP	Other	8/1/2005	20
Butler Ridge	WEC	Renewable	10/1/2005	54
Crescent Ridge	IP	Renewable	10/1/2005	51
Green Field Wind Farm	WEC	Renewable	10/1/2005	80
Kaukauna (WPPI)	WEC	Combustion Turbine	10/1/2005	52
Arrowsmith 267	AMRN	Renewable	12/1/2005	400
Faribault Energy Park	NSP	Combined Cycle	12/1/2005	250
Top Of Iowa Wind Farm II	ALTW	Renewable	12/1/2005	100
Blue Sky Wind Farm	WEC	Renewable	12/31/2005	80
Tremont Wind	GRE	Renewable	12/31/2005	100
Walworth County Wind Easement	MDU	Renewable	12/31/2005	50
Fenton Wind Power Project	NSP	Renewable	1/1/2006	200
Fremont Energy Center	FE	Combined Cycle	1/1/2006	700
Manitowoc	WPS	Steam Turbine	3/31/2006	63
Combined Cycle				3,385
Combustion Turbine				1,882
Other				20
Renewable				1,115
Steam Turbine				63
Total Capacity Additions (MW)				**6,465**

Source: Midwest ISO

Existing Unit Cost and Performance Characteristics

Existing unit cost and performance data was provided by the Midwest ISO and confirmed by Stakeholders during the data review process. Stakeholder comments were provided on a confidential basis and are therefore not included in this report. Note that ICF compared all Stakeholder data submissions to ICF standard assumptions, Midwest ISO data, and publicly available data when possible. Any inconsistencies were discussed with appropriate parties and resolved on a case-by-case basis. For example, generator capacity was reviewed in detail in comparison to historical bid and offer data. Some adjustments to Stakeholder data were made to reflect capacity actually available for dispatch during the study horizon. Appropriate care was taken to ensure that the effect of reserves was not double counted in this exercise.

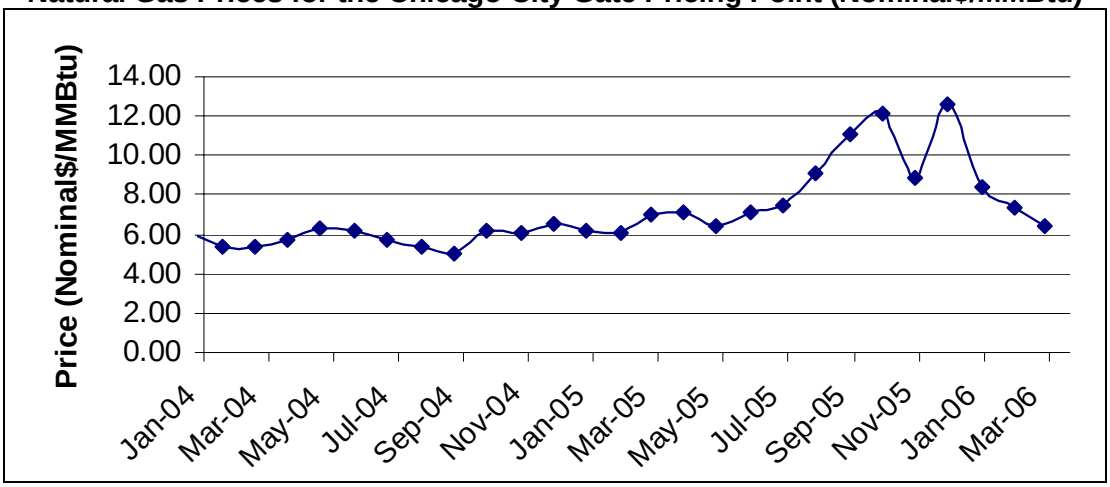
Unit Outages and Derates

ICF has explicitly modeled all unit outages and derates reported to the Midwest ISO during the study period. This data was provided by the Midwest ISO. Outages and derates were incorporated in the model on a daily basis for every generator within the Midwest ISO footprint, therefore any unit that experienced planned or unplanned outage extending at least one full day during the study period was made unavailable for the exact same duration during which it experienced an outage. This was done by assigning a start/stop date when the unit was unavailable. In the event that there was no derate reported to the Midwest ISO but historical generation records indicate that a unit was available at less than 100 percent for an extended period of time, ICF inferred derate where appropriate. These inferred derates were applicable to only a few units and did not significantly affect study results. The decision to utilize a daily average outage rate for every hour of the day means that in some hours the actual generating capacity was greater than simulated whereas in other hours the actual generating capacity was less than simulated. The larger the gap between actual and simulated generating capacity 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.

Natural Gas

A majority of the existing generation capacity within the Midwest ISO consists of low cost nuclear and coal units. As noted previously, natural gas has played an increasingly important role in the system as demand growth increases utilization of existing gas assets and almost all new capacity constructed in the past decade has been gas-fired. Combined cycles and combustion turbines, both of which rely on natural gas, accounted for over 80 percent of the new additions from April 2004 to March 2006; most of the remainder were intermittent renewable capacity. It is important to note that since mid-2002 natural gas prices have steadily increased and by late 2005, prices reached record levels. In 2005, the August – December average natural gas prices at Henry Hub reached close to $12/MMBtu with supplies curtailed as a result of Hurricane Katrina. Annual natural gas prices at Henry Hub averaged $8.89/MMBtu (2007$) in 2005, i.e., 33 percent higher than previous year levels. In 2006, natural gas prices averaged $6.80/MMtu (2007$), nearly 24 percent below 2005 average levels. While 2005 may have been a record year for high power and natural gas prices, the 2006 trend continued to show strong prices in both the fuel and power markets post-Katrina. This is evident in Exhibit 3-6 which shows, the gas prices from a representative pricing point for gas delivered to the Midwestern US, specifically the Chicago City Gate Pricing Point. Note that increased volatility in fuel markets was experienced during the later half of 2005. Between July and December 2005, the average monthly natural gas price increased by 69 percent on a nominal basis. This monthly average belies even greater volatility on a daily basis.

Exhibit 3-6:
Natural Gas Prices for the Chicago City Gate Pricing Point (Nominal$/MMBtu)



Source: Gas Daily

ICF developed natural gas price assumptions using historical delivered gas prices for the study period. ICF collected actual delivered gas prices for the various gas pricing points in the Eastern Interconnect. Every pricing point was mapped to ICF's gas supply regions. ICF used the monthly volume weighted average to calculate average monthly delivered gas price for every supply region. Each generator in the model is then mapped to a specific historical price stream based on geographic location and the pipeline network. Exhibit 3-7 shows the average monthly delivered natural gas prices utilized in this analysis.

Exhibit 3-7:
Delivered Natural Gas Prices (Nominal$/MMBtu) – January 2004 through March 2006

Month-Year	ECAR[1]	ECAR-KY[2]	ECAR-MECS[3]	MAIN-ILMO[4]	MAIN-WUMS[5]	MAPP[6]
Jan-04	6.34	7.91	6.01	6.11	6.09	6.00
Feb-04	5.64	5.92	5.48	5.39	5.40	5.24
Mar-04	5.61	5.67	5.58	5.42	5.43	5.11
Apr-04	5.98	6.03	5.96	5.72	5.73	5.36
May-04	6.55	6.65	6.51	6.31	6.32	5.92
Jun-04	6.56	6.59	6.41	6.20	6.22	5.85
Jul-04	6.16	6.16	6.15	5.69	5.87	5.68
Aug-04	5.68	5.62	5.65	5.38	5.44	5.26
Sep-04	5.35	5.19	5.16	5.00	4.95	4.60
Oct-04	6.50	6.19	6.33	6.21	6.05	5.50
Nov-04	6.44	6.31	6.29	6.12	6.12	5.95
Dec-04	6.89	7.08	6.64	6.58	6.64	6.43
Jan-05	6.24	7.02	6.24	6.16	6.16	5.96
Feb-05	6.36	6.50	6.29	6.12	6.13	5.85
Mar-05	7.18	7.34	7.15	6.98	7.01	6.64
Apr-05	7.57	7.51	7.41	7.06	7.09	6.88
May-05	6.78	6.72	6.64	6.44	6.45	6.04
Jun-05	7.44	7.50	7.27	7.11	7.11	6.56
Jul-05	7.83	8.07	7.58	7.42	7.43	7.10
Aug-05	9.73	10.22	9.34	9.12	9.14	8.63
Sep-05	11.20	11.73	10.40	11.03	11.09	9.04
Oct-05	14.15	14.21	13.07	12.15	12.15	11.10
Nov-05	10.50	10.29	9.40	8.85	8.93	8.21
Dec-05	13.23	13.70	12.47	12.57	12.53	11.82
Jan-06	9.03	9.50	7.25	8.43	8.46	7.89
Feb-06	7.94	8.28	7.67	7.40	7.43	7.26
Mar-06	7.30	7.37	6.78	6.36	6.45	6.15
Averages by Year						
2004	6.13	6.27	6.01	5.83	5.85	5.57
2005	9.03	9.25	8.62	8.43	8.44	7.83
2006	8.09	8.38	7.23	7.40	7.45	7.10

Source: Gas Daily, ICF

[1] ECAR: Actual delivered gas price as reported for Columbia Gas Pricing Point. ECAR includes Cinergy & First Energy.

[2] ECAR-KY; Actual delivered gas price as reported for Transco Pricing Point ECAR-KY includes Balancing Authorities in the state of Kentucky

[3] ECAR-MECS; Actual delivered gas price as reported for Michigan City Gate Pricing Point. ECAR- MECS region includes Detroit Edison and Consumers Energy

[4] MAIN-ILMO: Actual delivered gas price as reported for Chicago City Gate Pricing Point. MAIN-ILMO includes Balancing Authorities in Illinois & Missouri.

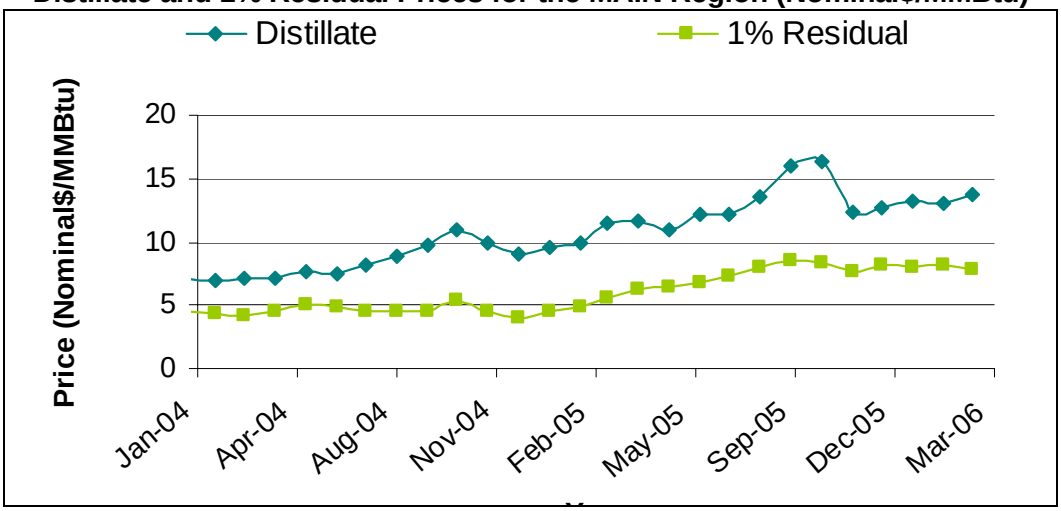
[5] MAIN-WUMS: Actual delivered gas price as reported for Alliance, Into Interstates Pricing Point. MAIN-WUMS includes Wisconsin & Upper Michigan.

[6] MAPP: Actual delivered gas price as reported for Northern Ventura Pricing Point. MAPP includes Balancing Authorities in the reliability region of MAPP.

Oil Prices

ICF used historical delivered oil prices during the study period for this analysis. The delivered oil price is a sum of the actual WTI monthly crude price from Bloomberg and estimated transportation differentials developed by ICF. Oil prices, most noticeably distillate oil prices, also increased significantly during the last quarter of 2005, though not as dramatically as natural gas. Exhibit 3-8 graphs the average monthly delivered distillate and 1 percent residual oil prices for the MAIN sub-region within the Midwest ISO. Exhibit 3-10 shows the average monthly prices of delivered oil to the ECAR, MAIN and MAPP sub-regions.

Exhibit 3-8:
Distillate and 1% Residual Prices for the MAIN Region (Nominal$/MMBtu)



Source: Bloomberg; ICF

Exhibit 3-9:
Delivered Oil Prices (Nominal$/MMBtu)

Month-Year	ECAR		MAIN		MAPP	
	Distillate	1% Residual	Distillate	1% Residual	Distillate	1% Residual
Jan-04	7.2	4.5	7.2	4.5	7.2	4.5
Feb-04	6.9	4.3	6.9	4.3	6.9	4.3
Mar-04	7.2	4.2	7.2	4.2	7.2	4.3
Apr-04	7.2	4.6	7.2	4.6	7.2	4.6
May-04	7.7	5.1	7.7	5.1	7.7	5.1
Jun-04	7.5	4.9	7.5	4.9	7.5	4.9
Jul-04	8.2	4.6	8.2	4.6	8.2	4.6
Aug-04	8.9	4.5	8.9	4.5	8.9	4.6
Sep-04	9.7	4.6	9.7	4.6	9.7	4.6
Oct-04	11.0	5.4	11.0	5.4	11.0	5.4
Nov-04	10.0	4.5	10.0	4.5	10.0	4.5
Dec-04	9.0	4.0	9.0	4.0	9.0	4.0
Jan-05	9.6	4.6	9.6	4.6	9.6	4.6
Feb-05	9.9	4.9	9.9	4.9	9.9	4.9
Mar-05	11.4	5.6	11.4	5.6	11.4	5.6
Apr-05	11.6	6.3	11.6	6.3	11.6	6.3
May-05	10.9	6.4	10.9	6.4	10.9	6.4
Jun-05	12.2	6.8	12.2	6.8	12.2	6.8
Jul-05	12.2	7.3	12.2	7.3	12.2	7.3
Aug-05	13.5	8.0	13.5	8.0	13.6	8.0
Sep-05	16.0	8.5	16.0	8.5	16.0	8.5
Oct-05	16.4	8.4	16.4	8.4	16.4	8.4
Nov-05	12.4	7.7	12.4	7.7	12.4	7.7
Dec-05	12.7	8.2	12.7	8.2	12.7	8.2
Jan-06	13.2	8.0	13.2	8.0	13.2	8.0
Feb-06	13.1	8.1	13.1	8.1	13.1	8.1
Mar-06	13.8	7.8	13.8	7.8	13.9	7.8
Averages by Year						
2004	8.38	4.60	8.38	4.60	8.38	4.62
2005	12.40	6.89	12.40	6.89	12.41	6.89
2006	13.37	7.97	13.37	7.97	13.40	7.97

Source: Bloomberg, ICF

Coal Prices

Coal units make up approximately 55 percent of the Midwest ISO capacity mix and more than 82 percent of the generation mix during the 2004 calibration period. Thus, the prevailing prices of coal are an important component of the analysis. In order to develop a consistent coal cost dataset ICF used delivered coal prices reported by SNL Financial (SNL) because the company has a comprehensive database of power plants with consistent data for the study time period

from June 2005 to March 2006. SNL bases this data upon reported coal prices for regulated facilities. Because unregulated coal plants are not required to report historical costs, SNL develops estimated fuel costs for these facilities based on fuel costs reported by similar regulated plants. SNL calculates the weighted average price from reported prices for each state and each fuel type and applies this to unregulated plants. ICF received a list of coal plants with accompanying data from SNL and matched the Midwest ISO coal plants to that list. SNL provided the following information:

- Name of coal plant;
- Fuel contract counter party;
- Fuel contract type (spot or contract);
- Amount of coal received for each contract (1,000 of tons);
- Delivered coal price (nominal$/MMBtu); and
- Sulfur content of coal for each contract.

ICF originally intended to use spot price as the best estimate of the replacement cost of coal prices during the study period. Unfortunately, due to the long-term contracts that dominate the coal industry, less than 40 percent of the reported prices were spot prices. While it may have been feasible to extrapolate the spot prices to cover all data points, available spot prices tend to cluster around a handful of coal plants. For most of the ten months, spot price data were available for less than 50 unique plants out of the more than 140 coal facilities in the Midwest ISO footprint. Because coverage was low, there was insufficient data to extrapolate a contract/spot relationship. Therefore, ICF used the total delivered price which is a weighted average of both spot and contract prices for each facility. The decision to utilize a weighted average coal price for every hour of the month means that in some hours the actual coal price was greater than simulated whereas in other hours the actual coal price was less than simulated. The larger the gap between actual and simulated coal price 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.

Exhibit 3-10 below shows a sample of representative coal plants and associated prices per month.

Exhibit 3-10:
Representative Delivered Coal Prices (Nominal$/MMBtu)

Plant Name	Balancing Authority	2005							2006			
		Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Average
Avon Lake	FE	1.48	1.50	1.50	1.51	1.54	1.44	1.60	1.65	1.68	1.74	1.56
Clay Boswell[1]	MP	1.03	1.00	1.00	1.00	1.02	1.04	1.04	1.02	1.02	1.02	1.02
Coal Creek[1]	GRE	1.04	0.79	0.85	0.87	0.89	0.83	0.71	0.86	0.80	0.87	0.85
Edgewater[1]	ALTE	1.26	1.17	1.23	1.23	1.35	1.37	1.41	1.41	1.60	1.52	1.35
Coffeen[1]	AMRN	1.11	1.09	1.17	1.15	1.15	1.13	1.18	1.24	1.27	1.34	1.18
Ghent	LGEE	1.68	1.67	1.65	1.77	1.79	1.79	1.81	1.85	1.90	2.12	1.80
Harding Street	IPL	1.45	1.45	1.45	1.46	1.56	1.58	1.58	1.43	1.46	1.42	1.48
R.M. Schahfer	NIPS	1.49	1.59	1.56	1.48	1.51	1.53	1.51	1.76	1.73	1.72	1.59
Sherburne County[1]	NSP	1.04	1.00	1.03	1.00	1.03	1.02	1.06	1.12	1.13	1.14	1.06
Walter C Beckjord	CIN	1.87	1.98	1.96	1.96	2.15	2.29	2.33	2.31	2.25	2.16	2.13

[1] Plant did not have any spot contracts during the study horizon.

Environmental Compliance Costs

As mentioned above, sulfur content for each coal contract was provided by SNL Financial. ICF developed a weighted average SO_2 content for each facility for each month for use in the model. Where appropriate, this fuel content was reduced to reflect installed scrubbers. Stakeholder and ICF data was used to develop a similar estimate of NO_X emission rates for all SIP Call affected facilities. These emission rates (lb/mmBtu) were then multiplied by the prevailing SO_2 and NO_X emission allowance prices ($/ton) to develop an hourly emission cost. Exhibit 3-11 below details the monthly SO_2 and NO_X prices utilized in this analysis.

Exhibit 3-11:
Title IV SO2 Allowance Prices and NOX SIP Call Prices (Nominal$/Ton)

Month-Year	SO_2	NO_X
Jan-04	248	2,611
Feb-04	267	2,325
Mar-04	274	2,149
Apr-04	279	2,017
May-04	333	2,196
Jun-04	394	2,276
Jul-04	541	2,452
Aug-04	482	2,236
Sep-04	487	2,101
Oct-04	568	2,159
Nov-04	678	2,297
Dec-04	706	2,233
Jan-05	700	3,570
Feb-05	654	3,428
Mar-05	688	3,414
Apr-05	841	3,330
May-05	805	2,940
Jun-05	758	2,401
Jul-05	812	2,287
Aug-05	858	2,598
Sep-05	885	2,485
Oct-05	968	2,647
Nov-05	1,319	2,475
Dec-05	1,587	1,950
Jan-06	1,503	2,722
Feb-06	998	2,577
Mar-06	910	2,459
Averages By Year		
2004	*438*	*2,254*
2005	*906*	*2,794*
2006	*1,137*	*2,586*

Source: *Air Daily*

Must-Take Contracts and Reliability Must-Run (RMR) Units

As noted in the Approach section, all economic contracts are assumed to be implicitly modeled. However, non-economic contracts such as those with must-take characteristics have to be pre-specified (forced) into the model. After detailed discussions with Stakeholders, no must-take contracts were modeled. Several facilities are considered “must-run” due to voltage and system support issues. These assumptions were provided by Stakeholders and are shown in Exhibit 3-12 below.

Exhibit 3-12:
Must Run Assumptions

Item #	Company	Unit	RMR Capacity (MW)	Comments
1	GenSys - Dairyland	JP Madgett	390 MW coal	All 3 need to be running at min load or higher in summer and winter. Must run except for Apr, May, Sept. and Oct. Only one unit (of 3) can go down during these 4 months
		Genoa 3 (G3)	365 MW coal	
	Alliant	Lansing 4	30 MW Coal	
2	Cinergy	Beckjord 1	94 MW Coal	Annual - One unit on at all times to support the 138 kV system.
3	Cinergy	Beckjord 2	94 MW Coal	Annual; One of the five units must be online at all times
	Cinergy	Beckjord 3	128 MW Coal	
	Cinergy	Beckjord 4	150 MW Coal	
	Cinergy	Beckjord 5	238 MW Coal	
4	WE Energies	Valley Coal	134 MW Coal	Annual with some variance in seasonal capacities
5	Alliant	6th Street- 3	2 MW Coal	Annual; One or more units must be operating at all times
	Alliant	6th Street- 4	16 MW Coal	
	Alliant	6th Street- 7	16 MW Coal	
	Alliant	6th Street- 8	31 MW Coal	
6	CMS	Midland Cogen	400 MW	Annual
7	Ameren	Hutsonville 3	31 MW Coal	Must run at minimum load in all peak hours
		Hutsonville 3	32 MW Coal	
8		Edwards 1	43 MW Coal	One unit must be operating at minimum load in all hours
		Edwards 2	110 MW Coal	
		Edwards 3	147 MW Coal	
9		Mexico	66 MW CT	One unit must be operating at minimum load if demand in Jefferson City exceeds 200 MW
		Morberly	66 MW CT	
		Morneau	66 MW CT	
10		Vermillion	Coal and CT	One unit must be operating an minimum load in all peak hours
11	Duke	Cayuga 1	300 MW Coal	One unit must be operating at 300 MW in all hours
		Cayuga 2	300 MW Coal	
12		Wabash 1	275 MW Coal – Summer 200 MW Coal – Winter	
14		Gibson 5	214 MW Coal – Summer 275 MW Coal – Winter	
14	First Energy	Bayshore 1	136 MW Petcoke	Must-run at maximum load

Source: Stakeholders; Midwest ISO

Demand-Side Assumptions

Exhibit 3-13 details the Midwest ISO membership included in ICF's study by year.

Exhibit 3-13:
Midwest ISO Membership

Member	Member in 2004?	Member in 2005?	Member in 2006?
Alliant East (ALTE)	Yes	Yes	Yes
Alliant West (ALTW)	Yes	Yes	Yes
Ameren (AMRN)	Yes	Yes	Yes
Central Illinois (CILC)	Yes	Yes	Yes
Cinergy (CIN/DEVI)[1]	Yes	Yes	Yes
Consumers Energy (ITC)	Yes	Yes	Yes
Columbia Water Light & Power (CWLD)	Yes	Yes	Yes
City Water Light & Power (CWLP)	Yes	Yes	Yes
Detroit Edison (ITC)	Yes	Yes	Yes
First Energy (FE)	Yes	Yes	Yes
Great River Energy (GRE)	Yes	Yes	Yes
Hoosier Energy (HE)	Yes	Yes	Yes
Illinois Power (IP)	Yes	Yes	Yes
Indianapolis Power and Light (IPL)	Yes	Yes	Yes
Louisville Gas & Electric (LGEE)[1]	Yes	Yes	Yes
Montana Dakota Utilities (MDU)	Yes	Yes	Yes
Madison Gas & Electric (MGE)	Yes	Yes	Yes
Minnesota Power (MP)	Yes	Yes	Yes
Northern Indiana Public Service (NIPS)	Yes	Yes	Yes
Northern States Power (NSP)	Yes	Yes	Yes
Ottertail Power Coop (MPC)	Yes	Yes	Yes
Southern Indiana Gas and Electric (SIGE)	Yes	Yes	Yes
Southern Illinois Power Coop. (SIPC)	Yes	Yes	Yes
Upper Peninsula Power (UPPC)	Yes	Yes	Yes
We Energies (WEC)	Yes	Yes	Yes
Wisconsin Public Service (WPS)	Yes	Yes	Yes

[1]DEVI and LGEE are no longer in the Midwest ISO market footprint as of June 2006 and September 2006, respectively. Since they were in the Midwest ISO before the end of the study period in March 2006, both were included in ICF's study. On the other hand, SMP (Southern Minnesota Municipal Power Agency) joined the market footprint in 4/2006, after the study period so was not included in ICF's analysis.

Historical energy demand for each Balancing Authority was provided by the Midwest ISO on an hourly basis for 2004, 2005, and relevant periods in 2006. Exhibit 3-14 details the Midwest ISO peak demand and net energy for load by Balancing Authority from 2004 to 2006 as derived from this data.

Exhibit 3-14:
Midwest ISO Peak Demand and Net Energy for Load

Balancing Authority	Peak Load (MW)			Average % of Midwest ISO's Total Peak Load	2004 Net Energy for Load (GWh)			Average % of Midwest ISO's Total Net Energy for Load
	2004	2005	2006		2004	2005	2006	
FE	12,357	13,697	12,190	11.80%	69,830	71,863	31,390	12.00%
HE	626	679	553	0.57%	2,841	3,361	1,450	0.57%
CIN	11,441	13,294	11,558	11.23%	64,842	68,808	29,578	11.30%
SIGE	1,761	1,835	1,664	1.63%	10,525	11,194	4,961	1.83%
LGEE	6,247	7,155	6,326	6.07%	34,388	37,223	15,869	6.07%
IPL	2,917	3,117	2,726	2.73%	15,417	15,984	6,867	2.63%
NIPS	3,269	3,630	3,358	3.17%	18,870	19,321	8,761	3.30%
ITC (MEC)	19,522	21,904	18,820	18.57%	104,325	108,469	46,554	17.93%
AMRN	11,949	12,920	10,656	10.93%	61,349	64,475	27,170	10.57%
IP	2,917	4,192	2,726	3.03%	15,417	20,964	6,867	2.90%
CILC	1,164	1,289	1,064	1.07%	5,754	6,087	2,458	0.97%
CWLP	441	468	379	0.40%	1,934	2,049	844	0.30%
SIPC	293	276	261	0.27%	1,428	1,424	614	0.20%
WEC	6,087	6,698	5,647	5.67%	34,879	35,669	15,211	5.93%
WPS	2,241	2,436	2,305	2.17%	13,939	14,373	6,276	2.40%
MGE	631	666	578	0.60%	3,357	3,396	1,466	0.60%
UPPC	154	215	149	0.13%	932	895	408	0.17%
LES	737	762	676	0.70%	3,279	3,464	1,468	0.60%
GRE	2,030	2,558	2,170	2.07%	6,962	13,141	5,667	1.87%
MPC	2,001	2,144	2,195	1.97%	11,802	11,974	5,587	2.07%
MP	1,868	1,848	1,717	1.70%	12,633	12,627	5,838	2.17%
ALTE	2,490	2,731	2,365	2.33%	13,454	13,925	6,092	2.30%
ALTW	3,464	3,745	3,332	3.27%	19,927	20,741	8,810	3.43%
NSP	8,808	8,797	8,395	8.03%	45,506	47,996	21,152	7.97%
Midwest ISO Total	**105,415**	**117,056**	**101,808**	**100%**	**573,591**	**609,423**	**261,357**	**100%**

Source: Midwest ISO

Operating Reserves

Spinning and Non-Spinning Reserve requirements in the Midwest ISO are determined separately for each Balancing Authority. The operating reserve criterion for each of these Balancing Authorities is based on their reliability council requirements. For example, the Balancing Authorities that fall under the MAIN reliability council use the MAIN operating reserve criteria to determine their requirements. Similarly Balancing Authorities that fall under ECAR and MRO reliability councils use their respective reliability council operating reserves requirements. Exhibit 3-15 shows the operating reserve criteria for the various balancing authorities under Midwest ISO market footprint during the study horizon[46]. Note that reserve requirements specified on a percentage basis such as those within the ECAR area were translated to a single annual MW requirement for modeling purposes.

Exhibit 3-15:
Operating Reserve Criteria for Midwest ISO Balancing Authorities

Balancing Authority	Spinning Reserve Requirement	Non-Spinning Reserve Requirement	Total Operating Reserve Requirement
ALTE	30.71	30.71	61.41
ALTW	56.29	56.29	112.58
AMRN	110.03	110.03	220.06
CILC	50	21.25	71.25
CE	266.22	266.22	532.43
CWLP	6.82	6.82	13.65
IP	54.14	54.14	108.28
MGE	9.4	9.4	18.8
SIPC	6	4	10
UPPC	1.5	1.5	2.99
WEC	87.43	87.43	174.87
WPS	31.89	31.89	63.78
GRE	41	62	103
MP	69	46	115
NSP	290	193	483
OTP	42	27	69
Total	**1,191**	**999**	**2,160**
CIN	2.5% * projected peak[47] load of the day	1.5% * projected peak load of the day	-
FE			
HE			
IPL			
NIPS			
LGEE			
DECO			
SIGE			

Source: Midwest ISO

[46] Note that these reliability organization footprints have changed significantly in recent years with the addition of Reliability First and the dissolution of MAIN.
[47] Peak load as calculated by respective Balancing Authorities

Following discussions with the Steering Committee we have included an additional 2,000[48] MW of operating reserve requirement in order to effectively simulate typical Midwest ISO operations. The additional reserves were added to entire Midwest ISO footprint to account for the following three reserve categories:

- Regulation reserves which are not explicitly characterized in the MAPS modeling framework;
- A portion of supplemental or non-spinning reserves which, according to Midwest ISO operators, are typically held as spinning reserves in day-to-day operations; and
- and "headroom" that is typically held by Midwest ISO dispatchers to allow sufficient dispatch and ramp capability to respond to changes in instantaneous load within the current multiple Balancing Authority structure.

These additional spinning reserves were allocated to Balancing Authorities based on the ratio of the actual spinning reserve requirements. Exhibit 3-17 shows the total megawatt spinning reserve requirement modeled in our Day-1 Case.

Exhibit 3-16:
Spinning Reserves Requirements for Midwest ISO Balancing Authorities

Midwest ISO Balancing Authority	Spinning Reserve Requirement (MW)
ALTE	68
ALTW	124
AMRN	243
CE	256
CILC	110
CIN	166
CWLD	13
DECO	404
FE	409
GRE	177
HE	35
IP	119
IPL	95
LGEE	88
MGE	20
MDU	2
MP	152
NIPS	97
NSP	640
OTP	93
SIGE	46
SIPC	13
CWLP	15
UPPC	4

[48] 800 MW for regulation reserves which Midwest ISO regularly holds, 700 MW to reflect the need for flexibility to meet instantaneous load in Real-Time operation, 500 MW to reflect the need for non-spinning reserves.

Midwest ISO Balancing Authority	Spinning Reserve Requirement (MW)
WEC	192
Total	**3,652**

Source: Midwest ISO

Consistent with current Midwest ISO operations, we have assumed that the 700 MWs of the total 3,652 MW of spinning reserves which is associated with regulation is optimized by the Midwest ISO across the entire footprint in the No-ASM Case. In the Day-2 Optimal Case these reserves are optimized across the entire footprint. We note that there is some variability surrounding the exact estimate of ASM related benefits depending on treatment of reserves. While this study was not as detailed in its estimation of the benefits of the proposed ASM market as some other studies, the estimate is reasonable based on the assumptions and consistent with findings in other studies.

Canadian Imports and Exports

Canadian regions of the Eastern Interconnect are not endogenously characterized in the version of MAPS utilized in this analysis. Any Midwest ISO interchange with Canadian provinces were specified instead as an hourly load or resource consistent with actual study period interchange, thus capturing the appropriate hourly impact of interchange with these areas in all cases analyzed. Exhibit 3-17 highlights the monthly the two most relevant net interchanges for the Midwest ISO. On average, the Midwest ISO imports 1,541 MW per month from Manitoba Hydro and exports 839 MW per month to the Ontario Independent Market Operator (IMO).

Exhibit 3-17:
Imports from Manitoba Hydro and Ontario Independent Market Operator

Month-Year	Manitoba Hydro	Ontario Independent Market Operator
Jun-05	1,307	-935
Jul-05	1,207	-445
Aug-05	1,483	-415
Sep-05	1,852	-1,006
Oct-05	1,884	-811
Nov-05	1,777	-820
Dec-05	1,656	-1,016
Jan-06	1,618	-1,073
Feb-06	1,539	-1,112
Mar-06	1,089	-759
Average	**1,541**	**-839**

Note: Positive numbers indicate imports into and negative numbers indicate exports from the Midwest ISO.

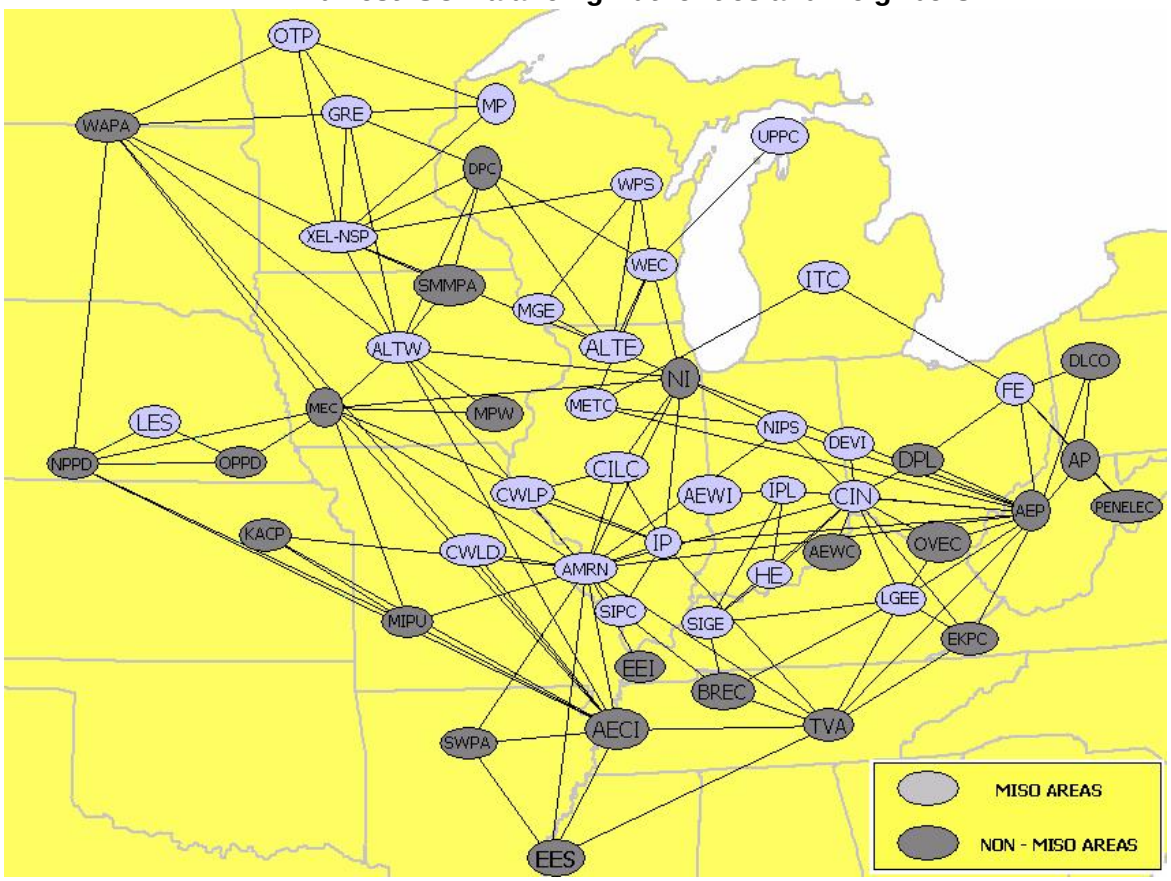
Transmission Assumptions

Network Model

For this analysis, ICF used a summer 2004 MMWG network model provided by the Midwest ISO. A network model provides MAPS with a detailed transmission system representation of the grid. All transmission facilities rated 69 kV and higher were explicitly modeled with their

normal, long-term, and short-term emergency limits based on data provided in Midwest ISO's network model. Exhibit 3-18 shows Balancing Authority interconnections for Midwest ISO and neighboring zones as specified in the Midwest ISO network model.

Exhibit 3-18:
Midwest ISO Balancing Authorities and Neighbors



Transmission Facility- Additions and Upgrades

This network model was modified to account for new line additions and upgrades for year 2005. The table below shows the transmission facilities that were added or upgraded in 2005. There were no major upgrades during the three months studied in 2006.

Exhibit 3-19:
Major Transmission Facility Additions and Upgrades

Project Description	Region	Ckt	Voltage (kV)	Action
Spurlock-Kenton	LGEE	2	138	Removed
North Appleton – Werner West-Rocky Run	ATC LLC		345	Up-rate
Lakefield to Fox Lake	XEL	1	161	Upgrade
Chanarambie - Lake Yankton - Lyon Co.	XEL	2	230	New 2nd transformer
Nobles to Chanarambie new 115 kV	Ameren	3	138	New Transmission Line
Maple River 230/115 kV Transformer	XEL	2	230/115	New 2nd Transformer
Beckjord to Silver Grove	Cinergy	1	138	New Transmission Line
Warren to Toddhunter	Cinergy	1	138	New Transmission Line
Madison West to Scottsburg	Cinergy	1	138	New Transmission Line
New Transformer at Scottsburg	Cinergy	1	138/69	New Transformer
Herbert Lake Transformer	MH	1	230/115	New 2nd Transformer
St. Francois – Rivermines	Ameren	3	138 Kv	New Transmission Line

Source: Midwest ISO

Flowgates

ICF has explicitly modeled all designated NERC and Midwest ISO flowgates[49] in this analysis. Flowgates are usually the sensitive and often stressed locations in the grid and the most frequent requiring generation redispatch to keep flows within limits. 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. There are approximately 1,000 NERC flowgates, 100 Midwest ISO flowgates and 10 rule-based limits (nomograms) that were modeled with explicit monthly limits for this analysis.

Although flowgate limits vary on an hourly basis, it is not practical to include hourly flowgate limits in the simulation model. ICF and Midwest ISO decided to model monthly limits. For Day-1 modeling, every flowgate limit was reduced by a certain percentage (Exhibit 3-20) 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.

[49] 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.

Exhibit 3-20:
Model Treatment of Flowgate Limits in Day-1 and Day-2

Region	Simulated Day-1 Case	Simulated Day-2 and No-ASM Cases
Midwest ISO - MAPP	84%	100%
Midwest ISO -ATC	89%	100%
Rest of Midwest ISO	91%	100%
SPP	91%	100%
Rest of the Eastern Interconnect	100%	100%

CHAPTER FOUR:
DETAILED STUDY RESULTS AND CONCLUSIONS

This chapter discusses: (1) calibration cases results, (2) study findings, (3) potentially conservative features of the analysis which may have resulted in underestimates of the achieved benefits and/or overestimates of achievable benefits, (4) comparison of the study findings with other studies, and (5) conclusions.

Calibration Case Results

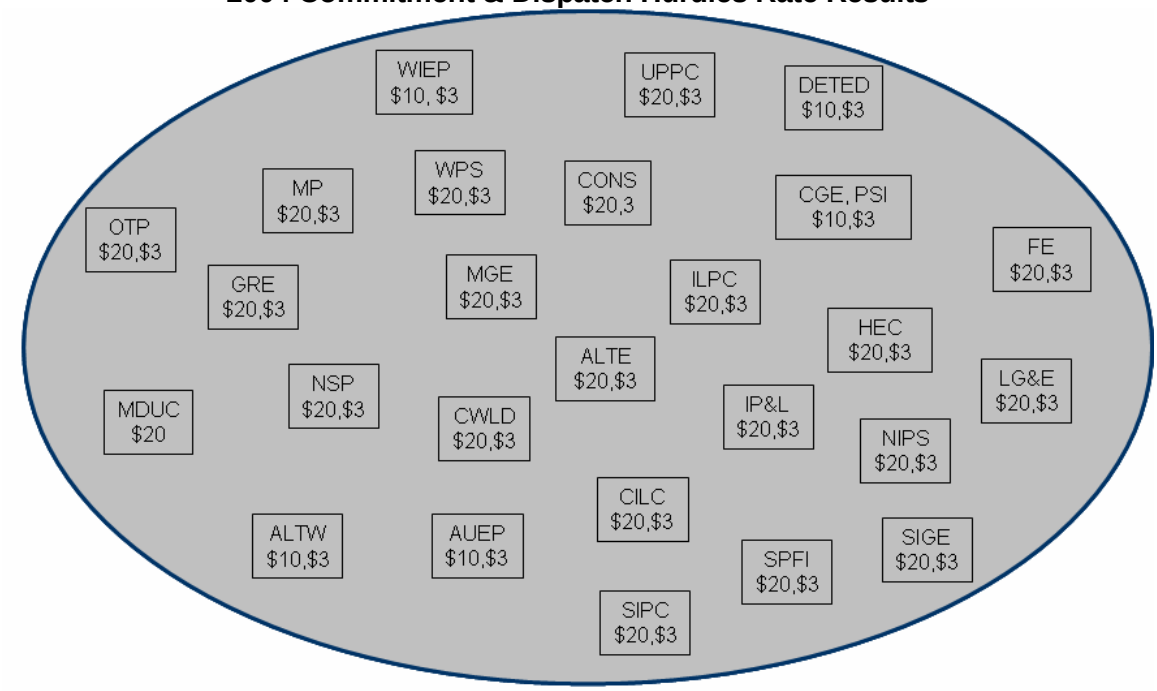
Calibrated Hurdle Rates

The determination of the appropriate level of hurdle rates is achieved through a detailed modeling exercise in which hurdle rates are introduced in the model to calibrate the simulated model outcome to historical market outcomes. The commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provides information to guide fine tuning 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[50]. Thus the total number of hours the 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 hurdles affecting that unit were adjusted. In contrast, if the unit was committed as expected, but did not dispatch as much as it actually did historically, then the appropriate dispatch hurdles were adjusted.

The primary result of the calibration process is a set of dispatch and commitment hurdle rates for each Balancing Authority in the Midwest ISO footprint. These results are shown in Exhibit 4-1 below. Through an iterative process we determined that a relatively low uniform $3/MWh dispatch hurdle combined with commitment hurdles varying between $10/MWh and $20/MWh provided the best calibration results. A $20 commitment and $5 dispatch hurdle was utilized into and out of the Midwest ISO as well as between all non Midwest ISO zones. This was sufficient to calibrate Midwest ISO net interchange during the study period.

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

Exhibit 4-1:
2004 Commitment & Dispatch Hurdles Rate Results



Control Area Name (Commitment Hurdle ($), Dispatch Hurdle ($))
Source: ICF Calibration Case

As discussed in Chapter Two above, these hurdle rates were translated from the 2004 Calibration Case to the Day-1 June 2005 to March 2006 case. This allowed us to simulate an expected commitment and dispatch result assuming that the Midwest ISO operated as a Day-1 market during the study period of June 2005 through March 2006. Hurdle rates were then removed from the model in our Day-2 Optimal and No-ASM cases to reflect fully efficient centralized commitment and dispatch. These hurdles are intended to simulate barriers to trade between Balancing Authorities. The change in production costs between the Day-1, Day-2 Optimal, and No-ASM Cases then yield the primary study results, i.e. the level of savings available due to restructuring of the Midwest ISO marketplace.

Note that generator input costs (i.e. the price of natural gas, coal, oil products, and emission allowances) varied significantly between the calibration and study periods as well as within the study period. Therefore, commitment hurdle rates in the Day-1 and No-ASM Cases were indexed to average natural gas prices on a monthly basis.

Calibration Statistics

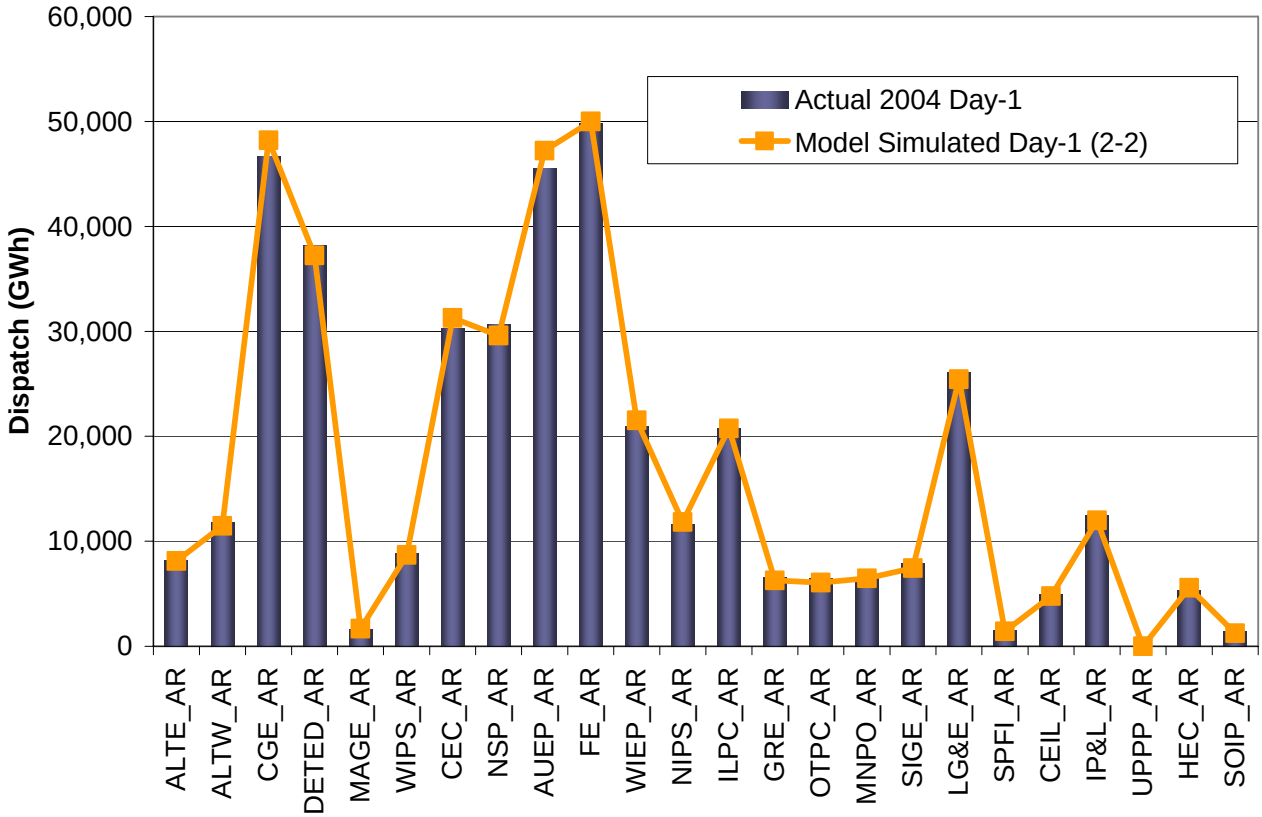
ICF performed a series of calibration cases while performing this study. Results of each case were compared against historical data and a final calibration case which represented a “best-fit” to historical market operation was chosen. ICF calibrated to four primary parameters during this exercise, namely Midwest ISO net interchange, generation by Balancing Authority, generation by unit type, and generation by unit. Exhibits 4-2 through 4-7 below demonstrate the excellent fit achieved during this exercise.

Exhibit 4-2:
Summary Calibration Statistics

Calibration Parameter	Correlation	R-Squared
Dispatch by Area	0.999	0.999
Dispatch by Unit Type	1.000	0.999
Dispatch by Unit	0.995	0.990

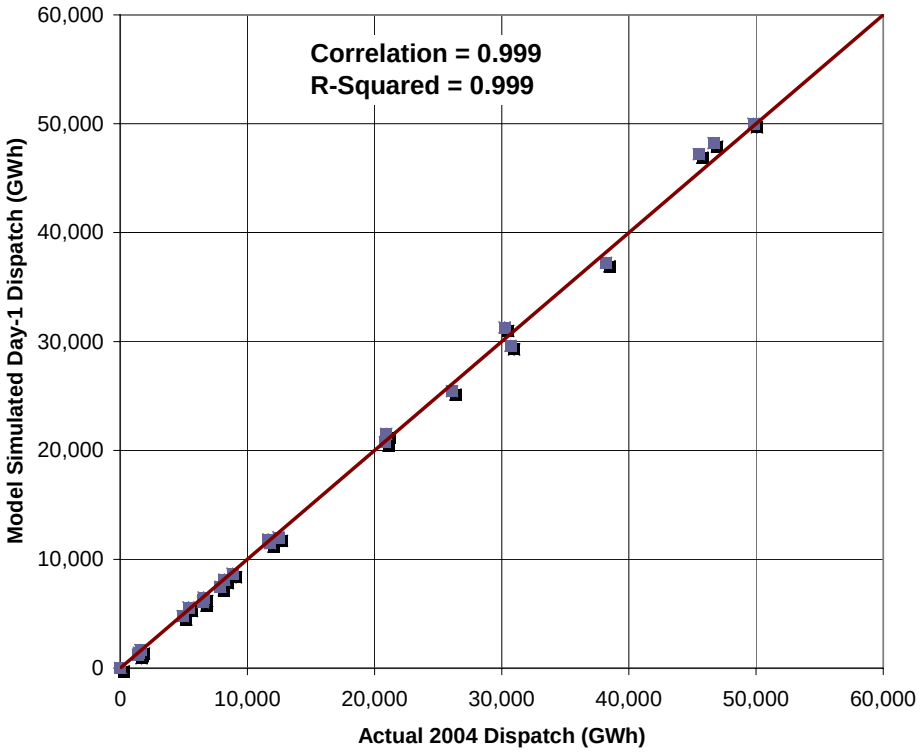
Source: ICF

Exhibit 4-3:
Total Dispatch by Balancing Authority – 2004 Actual vs. ICF Calibration



Source: ICF

Exhibit 4-4:
Total Dispatch by Balancing Authority– 2004 Actual vs. ICF Calibration



Source: ICF

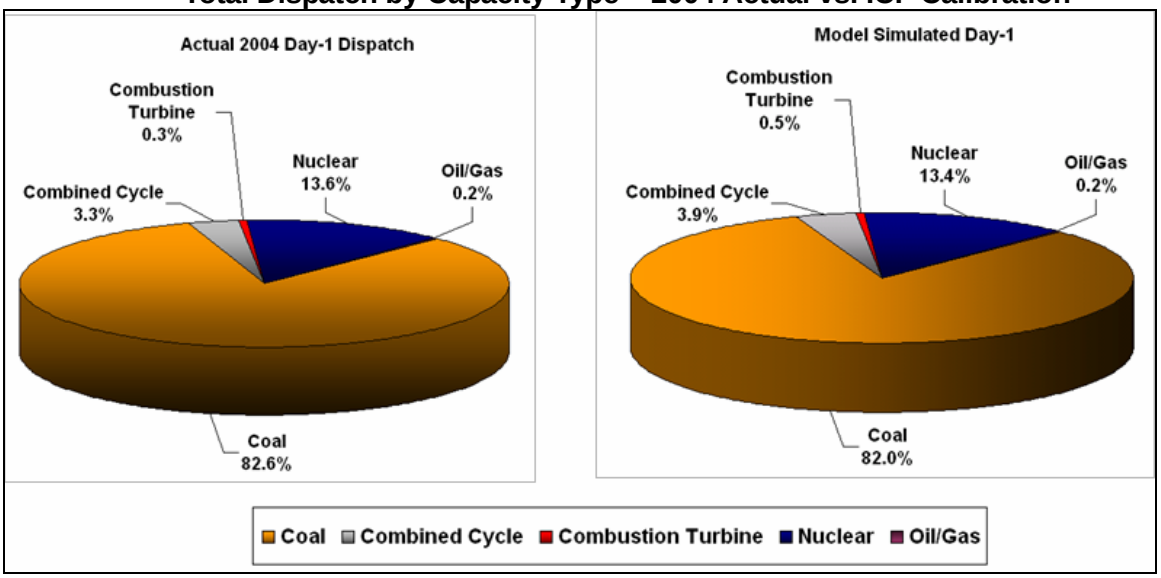
Exhibit 4-5:
Total Dispatch by Balancing Authority – 2004 Actual vs. ICF Calibration

Balancing Authority	Abbreviation	2004 Actual Dispatch	Calibration Results
Alliant East	ALTE	8,187	8,124
Alliant West	ALTW	11,780	11,467
Cinergy	CGE	46,657	48,215
Detroit Edison	DETED	38,207	37,231
Madison Gas & Electric	MAGE	1,596	1,665
Wisconsin Public Service	WIPS	8,830	8,688
Consumer's Energy	CEC	30,232	31,282
Northern States Power	NSP	30,699	29,609
Ameren	AUEP	45,500	47,208
First Energy	FE	49,792	50,005
Wisconsin Electric	WIEP	20,921	21,521
Northern Indiana Public Service	NIPS	11,646	11,826
Illinois Power	ILPC	20,807	20,757

Balancing Authority	Abbreviation	2004 Actual Dispatch	Calibration Results
Great River Energy	GRE	6,535	6,273
Otter Tail Power	OTPC	6,513	6,068
Minnesota Power	MNPO	6,566	6,481
Sothern Indiana Gas & Electric	SIGE	7,874	7,456
Louisville Gas & Electric	LG&E	26,095	25,440
Springfield Water & Power	SPFI	1,464	1,416
Central Illinois Lighting Co.	CEIL	4,905	4,779
Indianapolis Power & Light	IP&L	12,437	12,003
Upper Peninsula Power	UPPP	0	0
Hoosier Energy	HEC	5,364	5,567
Southern Illinois Power Corp	SOIP	1,405	1,237
Grand Total		**404,009**	**404,319**

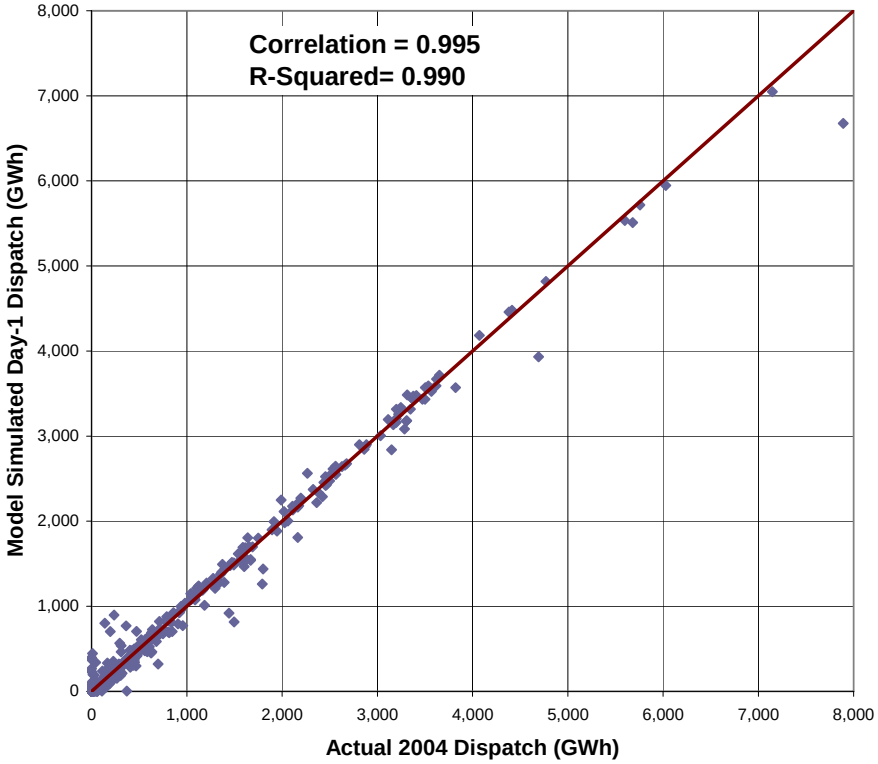
Source: ICF

Exhibit 4-6:
Total Dispatch by Capacity Type – 2004 Actual vs. ICF Calibration



Source: ICF

Exhibit 4-7:
Total Dispatch by Generator – 2004 Actual vs. ICF Calibration

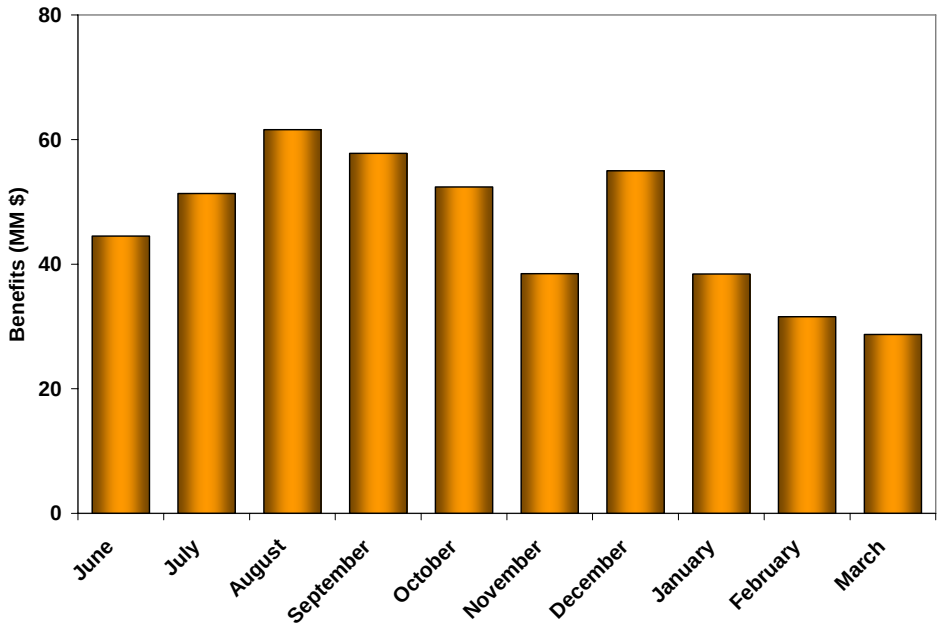


Source: ICF

Study 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 4-8 presents the maximum monthly benefits available in the Day-2 Optimal Case for the June 2005 to March 2006 period.

Exhibit 4-8:
Summary of Maximum Potential Benefits - June 2005 through March 2006



Source: ICF

Exhibit 4-9 compares the maximum potential, maximum achievable, and actual achieved benefits for the Midwest ISO during the ten month study period. The benefits are also shown on an annual basis assuming that average benefits extended at the same average level for an additional two months.

Exhibit 4-9:
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

Source: ICF

Our analysis yields the following three primary results:

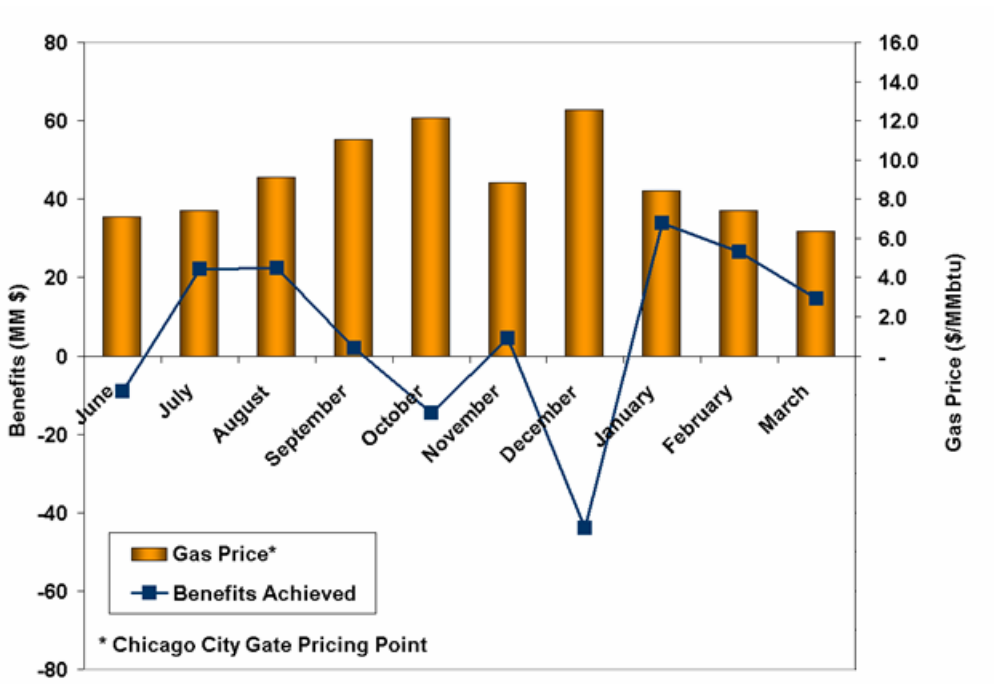
- Up to $460 million in benefits were potentially achievable through optimal operation of the Midwest ISO grid during the study period. This represents a 3.8 percent decrease in overall Midwest ISO production costs compared to the parallel Day-1 estimate. This

level of potential benefits is comparable to other studies of the potential benefits of centralized dispatch.[51]

- 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 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 further disaggregated results on a monthly basis. Exhibit 4-10 presents the actual benefits achieved on a monthly basis for the study period along with monthly average natural gas prices.

Exhibit 4-10:
Monthly Benefits Achieved and Historical Natural Gas Prices



Source: ICF

Exhibit 4-11 presents our monthly results of both maximum potential and actual achieved benefits in tabular form. Natural gas prices and the percentage of benefits achieved on a monthly basis are presented for reference as well. Note that emission allowance[52] and

[51] See Chapter 4 for a summary of previous study findings.
[52] See Exhibit 3-11 for additional detail.

delivered coal prices[53] also increased significantly during this period. For example, SO_2 allowance prices increased from $248 per ton in January 2004 to more than $1,587 per ton in December 2005.

Exhibit 4-11:
Monthly Potential and Achieved Benefits

Period		Theoretical Maximum Potential Benefits (MM$)	Actual Benefits Achieved (MM$)	Percentage Achieved
2005	June	44	(9)	(20%)
	July	51	22	43%
	August	62	22	37%
	September	58	2	3%
	October	52	(15)	(28%)
	November	38	4	11%
	December	55	(44)	(80%)
2006	January	38	34	88%
	February	32	27	84%
	March	29	14	50%
Total		**460**	**58**	**12%**

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.

Potentially Conservative Factors Vis-à-vis the Benefits Achieved and Achievable

Because this analysis compares the results of three MAPS model analyses with a detailed review of actual market operations during the study period, significant efforts were made to incorporate as many “real-world” phenomena as possible directly into the model. A number of these issues are discussed in Appendix A. While we believe that the majority of these issues are captured in our modeling, several variables could not be fully modeled within the MAPS framework or within the context of this study. Thus, there may be some features of the modeling that may have resulted in a conservatively low estimate of actual benefits achieved and/or a high estimate of achievable benefits. Some of these issues are discussed below, and the full set of issues considered in this regard is provided in Appendix A.

[53] See Exhibit 3-10 for additional detail.

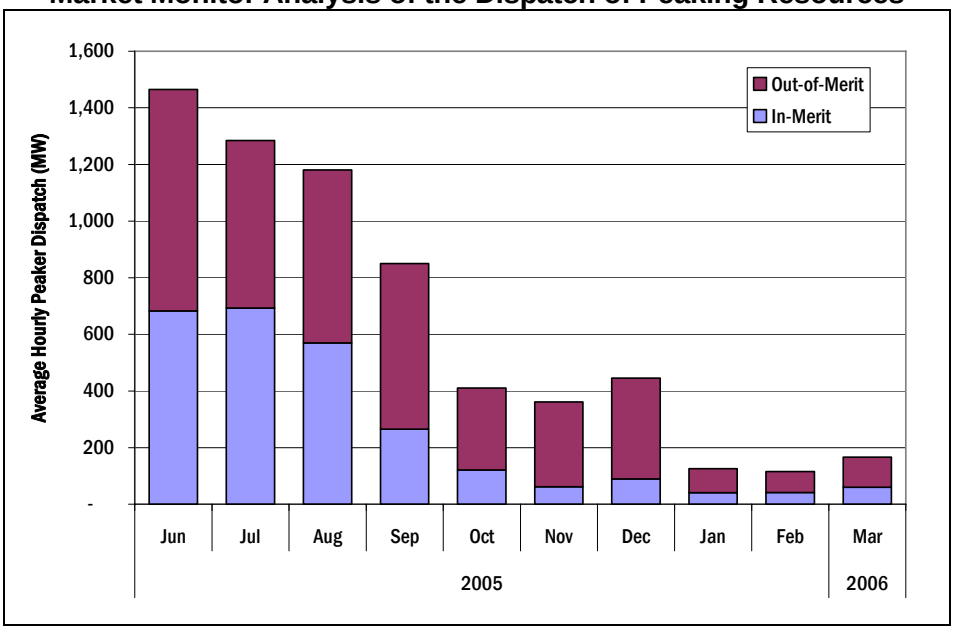
- **Choice of Calibration Year** – As discussed in Chapter 2, ICF, in consultation with the Study Steering Committee, chose 2004 as the calibration year due to data availability. During the review process, several stakeholders noted that 2004 was not an "average" year within the Midwest ISO footprint. Actual demand in the summer of 2004 was lower than expected and correspondingly we see that natural gas dispatch may have been lower than a "normal" year. The choice of a cooler than average year could potentially bias our calibrated hurdle rates downward, yielding a conservative estimate of potential benefits when these hurdle rates are translated to a hotter 2005 time period.
- **Day-Ahead vs. Real-Time Commitment** - While the MAPS model simulates a Day-Ahead market designed to minimize total production costs, a portion of the units required to reliably serve Real-Time demand and congestion management needs are committed after Day-Ahead market in the RAC process. The RAC process objective function is different than the Day-Ahead objective function in that the RAC commits resources in merit-order considering only start-up and no load costs. As a result the commitment obtained in MAPS may be more efficient (more optimal) that can be achieved in actual operations. In other words, when the MAPS model is dispatching peaking facilities to meet real-time load it optimizes overall production cost, assuming the ability to commit Day Ahead with perfect certainty, while the RAC process considers only start-up and no load costs and must be conducted in Real-Time when load is known with certainty. The consequence is that in actual operations units with lower start-up costs, but higher production cost may be committed. MAPS is not designed to simulate this particular market structure. We believe that all else being equal this difference may lead to an aggressive estimate of the potential achievable benefits. That is, some portion of the estimated $271 million in achievable benefits may not have been achievable given this difference between model and actual operations. This variable would not affect the estimate of achieved benefits. It may be valuable to further evaluate whether it would be beneficial to modify the Midwest ISO TEMT and systems to base the RAC process on minimization of total production costs, including start up and operating costs.
- **Bid Inflexibility** – The MAPS model assumes that all generators will, on average, submit bids with ramp rates and costs consistent with actual operating costs and physical facility operating limitations. This is not always the case during actual operations. Inflexible bids offered by market participants tend to limit the flexibility of dispatchers to respond to changing demand efficiently. Our assumption of fully flexible bids would tend to increase the estimate of achievable benefits. This issue is less important for the estimate of maximum potential benefits. In addition, to the extent inflexibility may have reduced actual benefits during initial market start-up, increasing flexibility is expected as participants gain operating experience and realize economic benefits of increasing the flexibility made available for dispatch.
- **Offered Capacity –** There is some evidence that initial stakeholder capacity assumptions[54] overstated the actual capacity offered by market participants in some months. Any overstatement of capacity would tend to decrease our model estimates of production costs and lead to a conservative estimate of actual benefits achieved. Based on evaluation of actual offer behavior during the study period, model assumption were refined, but it is not practical to include hourly or daily changes in offered capacity levels as occurs in Real-Time operations,

[54] See Chapter 3 for a discussion of how capacity assumptions were developed.

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 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.

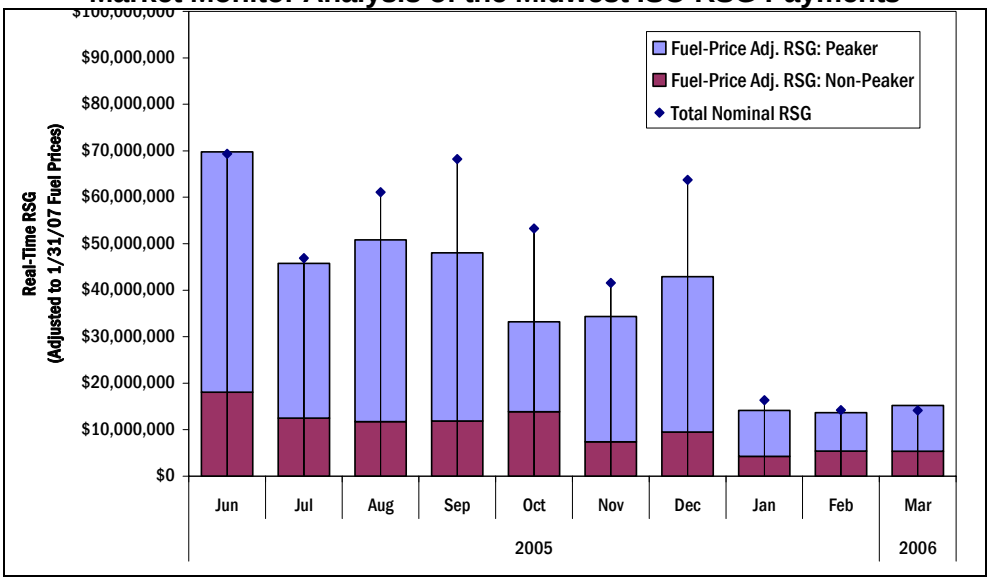
Exhibit 4-12:
Market Monitor Analysis of the Dispatch of Peaking Resources



Source: Midwest ISO Market Monitor Report Feb. 14, 2007

Our study results are also similar to a Midwest ISO review of Revenue Sufficiency Guarantee (RSG) trends shown in Exhibit 4-13 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.

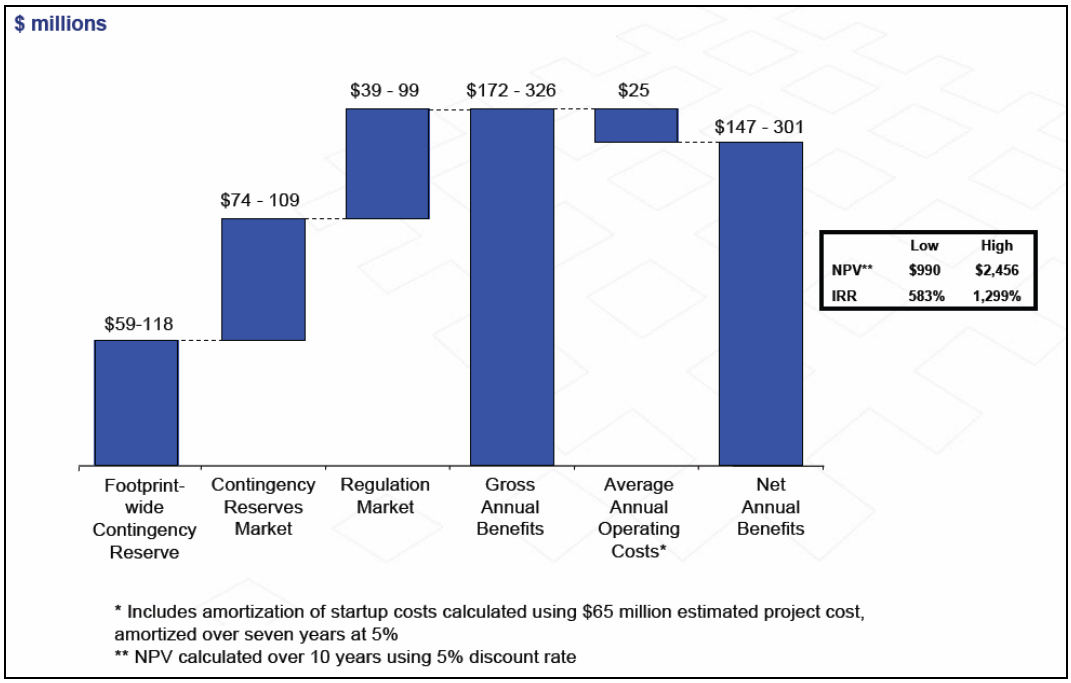
Exhibit 4-13:
Market Monitor Analysis of the Midwest ISO RSG Payments



Source: Midwest ISO Market Monitor report Feb. 14, 2007

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 "contingency reserves" and "regulation market" bars in Exhibit 4-14 below).

Exhibit 4-14:
Midwest ISO Estimates of ASM Benefits and Costs



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

Exhibit 4-15 shows some of the cost benefit studies associated with transitions from either Day-0 or Day-1 to greater coordination. This study estimated that the maximum potential cost savings to be 3.8 percent and hence is not dissimilar to findings in other studies.

Exhibit 4-15:
Summary of Previous Cost-Benefit Studies

Study Subject	Base Market Structure - Change Market Structure	Study / Forecast Period	Estimated Market Size - Energy Demand (TWh)[12]	Estimated Production Cost Savings Compared to Base Case
Midwest ISO [1]	Day-1 to Day-2 (No ASM)	Jul-05 to Mar-06	345	2.2%
	Day-1 to Day-2 ASM	Jul-05 to Mar-06		3.8%
Midwest ISO [2]	Day-2 to ASM	2006-2013[11]	345	1.1% to 2.2%[13]
Midwest ISO [3]	Day-1 to Day-2	N/A	345	5.8% to 14.0%[14]
Midwest ISO Short Term Study[4]	Day-1 to Day-2	7/7/2005	345	1.3%
		Peak Hour 7-Jul-05		2.6%
Midwest ISO [5]	Day-1 to Day-2	Peak Hour 7-Jul-03	345	22.7%
ERCOT[6]	Day-1 to Day-2	2005-2014	289	Approx. 1%
SEARUC[7]	Day-0 to Day-2	2004-2013	4,011	1.2% (SeTrans)
				1.8% (GridSouth)
				0.8% (GridFlorida)
				1.3% (Total SEARUC)
FERC RTO Benefit Study[8]	Day-0 to Day-2	2002-2021	4,011	0.6% (transmission only case)
				3.9% (RTO Case)
GridFlorida Cost Benefit Analysis[9]	Day-0 to Day-1	2004-2016	226	0.1% (Day-1)
	Day-0 to Day-2	2004-2016		1.4% (Delayed Day-2)
SPP[10]	Day-1 to Day-1 EIS	2006-2015	218	2.5%

[1] ICF International, *Independent Assessment of Midwest ISO Benefits*, February 28, 2007.
[2] Midwest ISO, *Midwest Contingency Reserve Sharing And Midwest ISO Ancillary Service Markets*, October 10, 2006.
[3] Midwest ISO, *Value Review: Analysis of Pre-MISO and Post-MISO Market*, October 19, 2005.
[4] ICF International, *Analysis of the Benefits of the Midwest ISO's Day-2 Market*, October 31, 2005.
[5] Ernest Orlando Lawrence Berkeley National Laboratory, *The Potential Impacts of a Competitive Wholesale Market in the Midwest: A Preliminary Examination of Centralized Dispatch*, October 2004.
[6] Tabors, Caramanis & Associates, *Market Restructuring Cost-Benefit Analysis for the Electric Reliability Council of Texas*, November 30, 2004.
[7] Charles River Associates, *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast*, November 6, 2002
[8] ICF International, *Economic Assessment of RTO Policy*, February 26, 2002.
[9] ICF International, *Cost-Benefit Study of the Proposed GridFlorida RTO*, December 12, 2005.
[10] Charles River Associates, *Cost-Benefit Analysis Performed for the SPP Regional State Committee*, April, 23, 2005.
[11] Historical 2004 data presented for illustrative purposes only.
[12] Estimated date range. Data includes amortization of startup costs over seven years estimated to begin in 2006.
[13] Note, this study did not explicitly report total production costs. Benefits were estimated at $172 to $326 million per year and were compared to ICF's estimate of Midwest ISO production costs, yielding 1.1% to 2.2% in production cost savings.
[14] Note, this study did not explicitly report total production costs. Benefits were estimated at $708 million to $1.8 billion per year and were compared to ICF's estimate of Midwest ISO production costs, yielding 5.8% to 14.0% in production cost savings.

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:

- 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. We note that there is some variability surrounding the exact estimate of ASM related benefits depending on treatment of reserves. For example, an alternative treatment of reserves might involve variation of reserves levels with demand on an hourly or monthly basis. While this study was not as detailed in its estimation of the benefits of the proposed ASM market as some other studies the estimate included in this study shows they represent a significant portion of total potential benefits.

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 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[55]. 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[56] 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 marketplace 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.

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

[56] 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.

Appendix A:
Issues Identified and Resolved by the Study Steering Committee

As discussed above, the study Steering Committee met regularly and was responsible for ensuring that this analysis included an accurate depiction of actual Midwest ISO operations. The table below highlights many of the issues identified by the Steering Committee and the associated resolutions.

Issue	Description	Resolution
1. Choice of calibration year	Because 2004 realized historically low dispatch of CT units throughout the Midwest ISO, the choice of 2004 as a calibration year may have biased hurdle rates downward and therefore limited potential benefits.	This is treated as a potentially conservative element of this analysis.
2. DA vs. RT Commitment	The Day-Ahead Market load typically clears below Real-Time load, requiring additional generation commitments in the Reliability Assessment Commitment (RAC). In an effort to avoid over committing generation in Real-Time, operators defer potential commitments identified in the Forward (Day-Ahead) RAC until closer to Real-Time. Units committed in Real-Time, when demand is more certain, tend to be faster starting units, typically CTs.	This variable was incorporated in the model as "load uncertainty" during the commitment stage of the modeling process.
3. "Head room" to account for shifts in instantaneous load	Real-Time operations under the currently divided Balancing Authority responsibilities required reserves held to respond to rapid demand changes in excess of those reserves held by Balancing Authorities to respond to generation and transmission contingencies. However, like many market models, MAPS models demand in a manner that is analogous to Day-Ahead (known and gradually changing load) rather than Real-Time (uncertain and responded to with 5-minute dispatch), and therefore does not reflect the increased need for regulation.	This variable was incorporated in the model as incremental reserves.
4. DA vs RT commitment algorithm	MAPS models a Day-Ahead market designed to minimize production costs. The Midwest ISO RAC objective function is to minimize start-up and no-load costs without consideration of incremental energy costs.	This is largely considered a potentially conservative element in the analysis, partially reflected in model treatment of load forecast error.

Issue	Description	Resolution
5. Co-optimized reserves	The Day-2-Optimal Case assumes co-optimized energy and reserves. The Midwest ISO market does not currently co-optimize these products. The ICF model reflects a scenario that includes implementation of ASM.	This is treated as a potentially conservative element of this analysis.
6. Centralized vs. decentralized reserves in Day-2	The Day-2-Optimal Case assumes the Midwest ISO manages reserves centrally in Day-2. Currently, reserves are held and managed by the Balancing Authorities.	The study involved a sensitivity case on this variable.
7. Hourly vs bi-hourly runs	Bi-hourly MAPS runs may reduce demand for peaking capacity.	It was confirmed that this is not a significant issue through testing and conversations with GE.
8. Transmission outages	No explicit modeling of transmission outages in the MAPS framework.	Review of actual transmission outages indicated that this is a minor issue with a relatively small effect on model results.
9. Interchange with exogenous regions	Actual Midwest ISO interchange with Manitoba and Ontario in the model, could be a potential issue because supply and demand for these regions are not explicitly included in the MAPS framework.	This was incorporated directly in the model. The approach is to model actual hourly net interchange between Midwest ISO and the exogenous Canadian regions in both the Day-1 and Day-2 Optimal Cases.
10. Losses in the Interchange Index	Appropriate treatment of losses in the calculation of Day-2 Actual costs could be important.	Losses are treated consistently between the actual and model cases.
11. Bias in the Powerflow Case	A need exists to review the powerflow case provided by the Midwest ISO for this analysis for any potential bias. MAPS utilizes a single power flow over study period and failure to assure representative power flow could result in model bias.	No potential bias was found

Issue	Description	Resolution
12. Bid Inflexibility	Midwest ISO market dispatch is based on market participant generation offers. MAPS model dispatch is based on assumed dispatch cost and unit physical characteristics. Market participants may choose to offer less that full unit flexibility restricting the dispatch and leading to suboptimal dispatch and therefore increased production costs. This inflexibility varies by hour and is not represented in the model.	This is treated as a potentially conservative element of this analysis.
13. ECOMAX	Stakeholder provided capacity assumptions should be validated against offered capacity to assure potential output levels are not overstated relative to the capacity available in the marketplace. Prior analysis by the Midwest ISO indicated large potential differences between annual nameplate capacity and capacity made available for hourly dispatch.	ICF, SAIC, and Midwest ISO staff Midwest ISO reviewed actual market bid data for the study period in detail and corrected for an initial 3 GW overstatement of capacity. The potential for monthly discrepancies is treated as a potentially conservative element of this analysis.
14. Offered ramp rates	Actual offered unit ramp rates may differ from physical ramp rates. This differential may limit the Midwest ISO's ability to achieve the full range of benefits possible.	See # 12 above.
15. Must-run	Market participants may offer more must-run units than are included.	See # 12 above
16. Historical outages and unit derations	Aggregate treatment of unit outages may not accurately reflect actual periods of shortage in the Midwest ISO system.	Analysis has incorporated all reported outages and unit derates in MAPS model.
17. Coal Prices	Analysis uses coal prices as an average of both contract and spot prices for each facility realized during the study period. This may not fully capture the volatility in coal markets during this period.	Because spot market coal transaction data is thin and not publicly available, ICF believes the approach and does not expect this to be a significant driver of either potential or actual benefits.
18. Treatment of wind and hydro	Wind and hydro require treated with appropriate operating patterns in the MAPS model.	Analysis inputs reflect appropriate dispatch patterns.

Issue	Description	Resolution
19. Taum Sauk	The Taum Sauk pumped storage facility has not operated since Dec 13, 2005.	Incorporated in the model
20. Behind-the Meter units	Treatment of BTM units in the model may affect results.	The BTM units were confirmed to be correct in the model.
21. Midwest ISO flowgate ratings in the D2-Optimal Case	The MAPS model reflects the assumption that transmission flowgate capacity is utilized at 100 percent of flowgate limit in the Day-2 Optimal Case. Real-Time operations are often below that limit.	Given the difficulty in developing a consistent model assumption to accurately reflect this issue we have assumes 100 percent utilization in the Day-2 and No-ASM cases.
22. Hourly vs. instantaneous load	MAPS model reflects integrated (average) hourly load. Capacity commitments must be adequate to cover instantaneous load during the peak hour.	This variable was incorporated in the model as “load forecast error” during the commitment stage. (see #3 above for related discussion)