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July 25, 2009

Stephanie Strength
Environmental Protection Specialist
USDA, Rural Utilities Service
Engineering and Environmental Staff
1400 Independence Avenue, SW., Stop 1571
Washington, DC 20250-1571

via email: stephanie.strength@usda.gov

RE: CapX 2020 – EIS Scope

Dear Ms. Strength:

Thank you for the opportunity to raise comments regarding the scope of the RUS EIS. In this Comment, I will frequently be referring to exhibits from the Certificate of Need proceeding, which is where the purpose and scope of the project as proposed are readily apparent.

I. <u>The RUS EIS must address impacts of entire CapX 2020 Phase I.</u>

B-019-001 CapX 2020 Phase I is the largest transmission project in the history of the State of Minnesota! The entire project is a part of a whole, a phased and connected action, an interdependent project. In its application to RUS, CapX 2020 is misrepresented as only a part of a project, with only the Hampton to LaCrosse part claimed. This is grossly misleading, and circumvents the necessary environmental review. CapX 2020 is one large project, developed and applied for in the Certificate of Need proceeding as one project. It was developed as a whole, applied for as a whole, it's all connected, it's environmental impacts are connected.

CapX 2020 was developed as an integrated project.

- It was sold to the Legislative Electric Energy Task Force as an integrated plan for Minnesota and Regional need. NoCapX & U-CAN Exhibit A, CapX 2020 Presentation to Legislative Electric Energy Task Force, September 14, 2004.
- CapX 2020 was presented to the public in September, 2005, as a "comprehensive framework:"

B-019-001

Your comment has been noted. Dairyland Power Cooperative, one of the CapX2020 utilities, has requested financial assistance from USDA Rural Utilities Service (RUS), for Dairyland's anticipated 11 percent ownership interest in the proposed Hampton-Rochester-La Crosse 345 kilovolt transmission line project. RUS has determined that its funding of Dairyland's ownership interest is a federal action and therefore subject to the National Environmental Policy Act (NEPA) and Section 106 of the National Historic Preservation Act (NHPA). RUS is the lead agency for both NEPA and Section 106 review.

In preparation of the EIS, RUS is reviewing the funding request from Dairyland within the laws, policies, and guidelines that apply to the request.

Over the last year, transmission planners have worked to develop a comprehensive framework for much needed transmission infrastructure for the state of Minnesota. Instead of a piecemeal approach in which each individual electrical issue is studies and addressed separately, we endeavored to integrate our planning efforts and identify common improvements to the high voltage transmission system over a broad spectrum of possible futures.

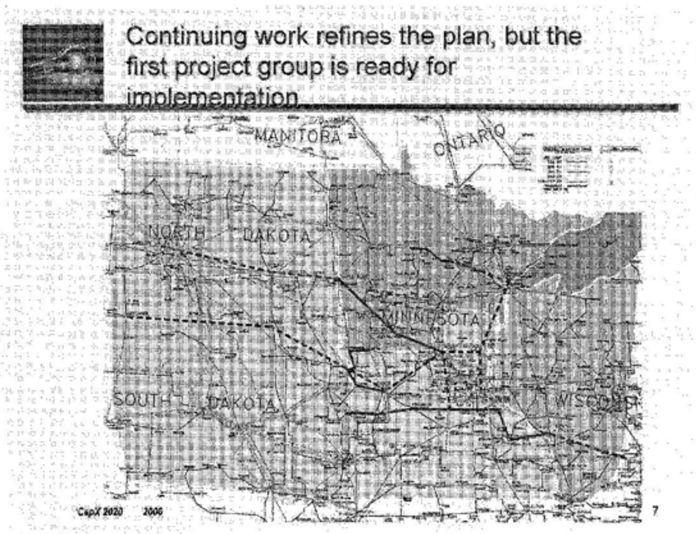
NoCapX 2020 & U-CAN Exhibit B, CapX Letter to PUC, Sept. 6, 2005.

CapX 2020 Phase I, as proposed in the Certificate of Need proceeding, and as stated in CapX presentations and letters, samples above, is a web of integrated and comprehensive transmission lines:

- Fargo-St. Cloud-Monticello, 250 miles, 345-kV
- Brookings County-Hampton, 200 miles, 345-kV
- Hampton-Rochester-La Crosse, 150 miles, 345-kV

B-019-002 The connection of the two southern segments is literal, with it running from Brookings County to Hampton to Rochester to LaCrosse. Any separation into segments is artificial – it is electrically designed to be "all connected."

Look at the maps. CapX 2020 as studied and proposed, stretches from the coal fields of the Dakotas, through Minnesota, to central Wisconsin:



B-019-002

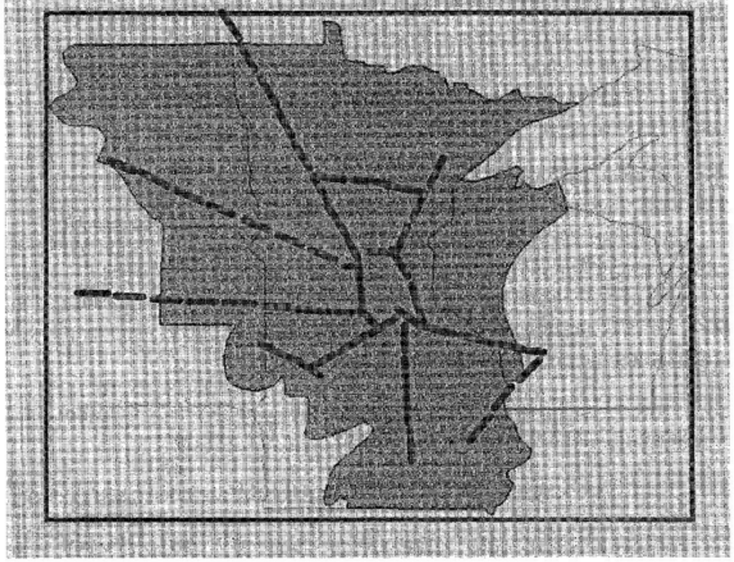
Your comment has been noted.

While the CapX2020 projects involve four independent projects being developed in a similar time frame with some of the same of utilities participating, the Purpose and Need for the CapX2020 Hampton-Rochester-La Crosse 345-kV Project was developed and proven independently of the other CapX2020 projects. The Alternative Evaluation Study addresses project Purpose and Need and is available at: http://www.usda.gov/rus/water/ees/eis.htm, which has been approved by the RUS. Purpose and Need will also be addressed in the Draft Environmental Impact Statement.

NoCapX & U-CAN Exhibit C - CoNHearing Exhibit 13[1], Slide 7 to Hearing Exhibit 12, CapX 2020 Update, June 12, 2006[2].

When CapX overlays its geographic area with its transmission "vision" in its application, this interconnected web of transmission is the result:

Figure 1-9: Geographic Scope of CapX2020



The Certification of Need application is for three transmission lines in Phase I of at least three phases. NoCapX & U-CAN Exhibit D, CoN Hearing Ex. 12, Slide 16, CapX 2020 Update, June 14, 2006.

The application and appendices to the Minnesota Public Utilities Commission clearly and repeatedly lays out specific plans for an even bigger "comprehensive" project, in at least three Phases of transmission infrastructure additions. The lines chosen for the immediate Phase I are from a list of common facilities from various scenarios, on the belief that these will need to be built no matter which scenario is presumed[3]. In table form, these "common elements" are:

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[1] Available online: https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5465628

[2] Ex. 12 available online: https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5465627

[3] See Common Recommended Facilities, Hearing Exhibit 1, Application, Appendix A-1, p. 38; Common Recommended Facilities, Rogelstad, Direct p. 17; Rogelstad Testimony, Tr. Vol. 2A, pps. 59-76; Exhibit 17, 2005 Biennial Report Filed by Transmission Utilities (selected); Rogelstad Testimony, Tr. Vol. 2A, p. 71-78.

TABLE OF SYSTEM ELEMENTS COMMON TO ALL SCENARIOS

Facility Name				
From	**To**	**V olt (kV)**	**Miles**	**Cost ($M)**
Alexandria, MN	Benton County (St. Cloud, MN)	345	80	60
Alexandria, MN	Maple River (Fargo, ND)	345	126	94.5
Antelope Valley (Beulah, ND)	Jamestown, ND	345	185	138.75
Arrowhead (Duluth, MN)	Chisago County (Chisago City, MN)	345	120	90
Arrowhead (Duluth, MN)	Forbes (Northwest Duluth, MN)	345	60	45
Benton County (St.Cloud, MN)	Chisago County (Chisago City, MN)	345	59	44.25
Benton County (St. Cloud, MN)	Granite Falls, MN	345	110	82.5
Benton County (St. Cloud, MN)	St. Bonifacius, MN	345	62	45.5
Blue Lake (Southwest Twin Cities, MN)	Ellendale, ND	345	200	150
Chisago County (Chisago City, MN)	Prairie Island (Red Wing, MN)	345	82	61.5
Columbia, WI	North LaCrosse, WI	345	80	60
Ellendale, ND	Hettinger, ND	345	231	173.25
Rochester, MN	North LaCrosse, WI	345	60	45
Jamestown, ND	Maple River (Fargo, ND)	345	107	80.25
Prairie Island (Red Wing, MN	Rochester, MN	345	58	43.5
TOTAL			**1620**	**$1,215 ($M)**

NoCapX & U-CAN Exhibit E – Common Elements, also CoN Hearing Exhibit 17, Portion of the 2005 Biennial Report Filed by Transmission Utilities, p. 36; Hearing Ex. 1, Application, App. A-1, Technical Update October 2005; see also Hearing Exhibit 12, CapX 2020 Update, June 14, 2006; Hearing Testimony Rogelstad, Vol. 2A, p. 69-74; Hearing Testimony Rogelstad, Direct p. 17; Hearing Testimony Rogelstad, Tr. Vol 2A, p. 39.

In its press release of April 3, 2009, CapX reveals more of the interconnected aspect of CapX, admitting that it must have an extension of the project beyond North LaCrosse, into Wisconsin, as without that generation outlet, the project will cause

> *The studies also found that further upgrades in Minnesota and the Dakotas (beyond the 230-kilovolt line upgrade)will not provide significant benefit prior to installation of a high-voltage transmission line between the La Crosse,Wis., area and the Madison, Wis., area.* **Without a line to the east of Minnesota, the transmission system will reach a "tipping point" where reliability is compromised,** ***according to the studies.*** *The studies found that the combination of the new 345-kilovolt double circuit line between Granite Falls and Shakopee and a new Wisconsin line would increase the transmission*

system transfer capability by 1,600 megawatts for a total increase -- with the 2,000 megawatts from the new 345-kilovolt line in Minnesota – of approximately 3,600 megawatts.

NoCapX & U-CAN Exhibit F, CapX Press Release, April 3, 2009.

The USDA's Rural Utilities Service cannot ignore all the evidence that this is one large connected project. RUS funding, though only for a part, is for an integral part, without which the project would not happen. Without RUS funding, the project as a whole may go forward, but it will go forward only with all of the pieces – the RUS funded piece is necessary to the whole.

B-019-003

RUS participation confers responsibility to address the impacts of the project as a whole.

II. Minnesota Dept. of Commerce circumvented a necessary and predictable joint EIS with RUS

The Minnesota Dept. of Commerce improperly avoided a joint EIS for the Certificate of Need by making the following declarations in its scoping decision for the Certificate of Need:

> It is not possible to associate this environmental review with any federal review at this time. Minnesota Rule 4410.3900 anticipates coordinating state and federal review where possible. However, the association is not possible in this case due to timing and relevance. First, completion of this ER is required for the contested case hearing prior to when any application initiating potential federal review would be filed.
>
> Additionally, no application for a permit or funds from the Rural Utility Service is anticipated by any of the applicants. No action requiring a federal EIS is anticipated. If that situation were to change when any route applications are filed, the Department would pursue all opportunities to coordinate the EIS reviews in those proceedings with any relevant federal agency reviews.

The premise of these paragraphs is false. First, it was assuredly "possible to associate this environmental review with any federal review at this time." At that time, it was obvious that there would be federal review. Multiple parties, in their Certificate of Need scoping Comments, requested a joint RUS and Commerce EIS, knowing that Dairyland Power was seeking RUS finding for its part of the CapX project. Secondly, RUS funding was anticipated, and again, multiple parties requested a joint RUS and Commerce EIS.

B-019-004 This gross deficiency of environmental review must be corrected. Impacts of the entire project will occur if enabled by RUS funding. The RUS can and should include the entire project within the scope of the EIS.

III. Multiple Mississippi and Minnesota river crossings will occur if this project goes forward

The planned and alternative routes for CapX 2020 would cross the Minnesota River and the Minnesota River Scenic Byway twice, and would cross the Mississippi River and the Mississippi River Scenic Byway.

B-019-003

Your comment has been noted. Please refer to comment response B-019-002 regarding connected actions.Dairyland Power Cooperative, one of the CapX2020 utilities, has requested financial assistance from USDA Rural Utilities Service (RUS), for Dairyland's anticipated 11 percent ownership interest in the proposed Hampton-Rochester-La Crosse 345 kilovolt transmission line project. RUS has determined that its funding of Dairyland's ownership interest is a federal action and therefore subject to the National Environmental Policy Act (NEPA) and Section 106 of the National Historic Preservation Act (NHPA). RUS is the lead agency for both NEPA and Section 106 review.

B-019-004

Your comment has been noted. Dairyland Power Cooperative, one of the CapX2020 utilities, has requested financial assistance from USDA Rural Utilities Service (RUS), for Dairyland's anticipated 11 percent ownership interest in the proposed Hampton-Rochester-La Crosse 345 kilovolt transmission line project. RUS has determined that its funding of Dairyland's ownership interest is a federal action and therefore subject to the National Environmental Policy Act (NEPA) and Section 106 of the National Historic Preservation Act (NHPA). RUS is the lead agency for [illegible]

B-019-005 A. The RUS EIS must address impacts on river crossings of Minnesota and Mississippi Rivers.

B-019-006 B. The RUS EIS must address impacts on the National and Minnesota Scenic Byways.

B-019-007 C. The RUS EIS must address impacts on the federally protected wildlife areas along both the Mississippi and Minnesota rivers. Both river valleys contain protected wildlife areas that would be affected by the crossings and the impacts must be analyzed. The corridors for CapX 2020 cover much of the state, crossing or parallelling the Mississippi River and the Minnesota River.

B-019-008 **IV. <u>The RUS EIS must address various scenarios of CapX 2020 enabling coal generation.</u>**

A. CapX 2020 begins at the coal fields of the Dakotas, and specifically interconnects to Big Stone II at the Granite Falls substation. The A rate capacity of the lines is 4,100MVA, and according to Jeff Webb, MISO, there is 3,441MW of coal generation waiting in line in the MISO queue. The wind lobby talks of getting 700MW of wind, meaning that capacity attributable PERHAPS to wind is about 1/6 of A rate capacity, and the rest could well be coal.

B. The RUS EIS should address impacts assuming various percentages of coal against the A rate capacity of the conductors:

o 10% - 410 MW
o 30% - 1,230 MW
o 50% - 2,050 MW
o 75% - 3,033 MW
o 85% - 3,485 MW

Coal generation is a purpose of CapX 2020 and the MISO (and all other ISOs) shift to economic dispatch and declarations of the "benefits" possible and realized. From MISO's Independent Assessment of Midwest ISO Operational Benefits, an express purpose is displacing natural gas with coal:

> 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

B-019-005

Your comment has been noted. Potential impacts to water quality will be addressed in the Draft Environmental Impact Statement.

B-019-006

Your comment has been noted. Potential impacts to the aesthetic quality of the areas surrounding the transmission line will be addressed in the Draft Environmental Impact Statement.

B-019-007

Your comment has been noted. Potential impacts to wildlife will be addressed in the Draft Environmental Impact Statement.

B-019-008

Your comment has been noted. Due to the transmission grid's interconnected nature as well as to electricity's nature - it's generally difficult to identify a specific source of electricity on the grid.
The proposed CapX2020 transmission lines will serve the region's expected growth and help begin to meet Minnesota's Renewable Energy Standard (RES), which requires utilities to deliver 25 percent of their electricity from renewable sources by 2025 (Xcel Energy is mandated to deliver 30 percent by 2020, with 25 percent from wind). Most of that energy comes from wind turbines. Cumulative impacts and connected actions will be addressed in the Draft Environmental Impact Statement.

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.

NoCapX & U-CAN Exhibit G, Independent Assessment of Midwest ISO Operational Benefits, p. 14; see also Conclusions, p. 83-84..

Implementation of CapX 2020 will increase utilization of coal generation in the MISO footprint. Therefore, the RUS' EIS must address the impacts of increasing coal generation in various percentage scenarios.

V. <u>The RUS must independently verify CapX's need claim – demand has dropped</u>

B-019-009 The RUS EIS must independently verify CapX's need claim. The Minnesota Department of Commerce accepted the applicant's need claims without independent verification. However, demand has dropped significantly and utilities are rethinking infrastructure investments. NoCapX & U-CAN Exhibit H, Surprise Drop in Power Use Delivers Jolt to Utilities, November 21, 2008, Wall Street Journal.

In today's reality of significantly decreased demand, and governmentally mandated and consumer driven conservation efforts, need claims must be substantiated. Demand is down – dramatically, and CapX 2020 isn't needed.

Xcel falsely claims in handouts at the June 16th, 2009 Plainview RUS public meeting that:

Electricity usage continues to climb

Why does the electric transmission grid need to be expanded? The simple answer: Because we're using more electricity than we did just a few years ago – and it's expected to grow another 40 percent by 2030.

False? Yes, and I drew this to the attention of Stephanie Strength at the meeting and requested that this flyer be pulled..

Take a look at Xcel's SEC 10Ks for 2008[4], 2006[5] and 2002[6] for electric demand:

System Peak Demand (in MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008
7,936	8,344	8,259	8,868	8,665	9,212	9,859	9,427	8,697

[4] Xcel 2008 SEC 10-K: http://www.secinfo.com/$/SEC/Filing.asp?D=Vut2.s1Uy
[5] Xcel 2005 SEC 10-K: http://www.secinfo.com/d11MXs.vbn4.htm
[6] Xcel 2002 SEC 10-K: http://www.secinfo.com/dsvrp.24u6.htm#_008

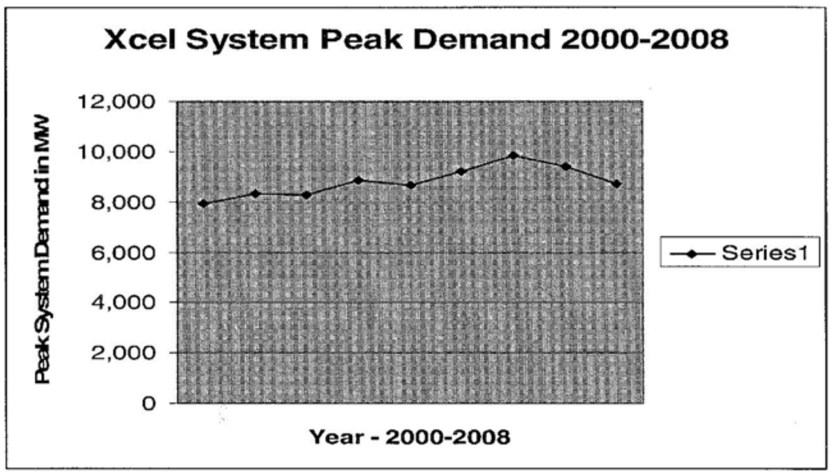
B-019-009

Your comment has been noted. The criteria used to route the transmission line is described in the Macro Corridor Study which is available on the RUS website at: http://www.usda.gov/rus/water/ees/eis.htm. These criteria and routing process will be addressed in the Draft Environmental Impact Statement. The project is still in the development and planning stages and the utilities have not yet permitted a route for the transmission line.

Xcel's Investor Relations Earnings Release 2008 Year End Summary[7], issued January 29, 2009 and unavailable at the time of the CapX 2020 hearing, clearly discloses the drop on demand:

> **During 2008, we experienced flat electric residential sales, primarily driven by a decline in the NSP-Minnesota region. We believe the flat sales growth is a reflection of a recent shift in customer behavior, in part, attributable to the overall economic conditions as well as conservation efforts.**

Exhibit I, Xcel 2008 Year End Summary, p. 5 (emphasis added). Electric residential sales, actual, were at -2% for 2008, normalized to 0.0%. Id. A flat rate would alter the size, type and timing of any forecasted need. Xcel's 2008 10-K reveals even more:



NoCapX & U-CAN Exhibit J, Xcel 2008 10-K (selected). From this 10-k, p. 19:

> **Capacity and Demand**
>
> Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2009, assuming normal weather, is listed below.

System Peak Demand (in MW)

2006	2007	2008	2009 Forecast
9,859	9,427	8,697	9,662

The peak demand for the NSP System typically occurs in the summer. The 2008 system peak demand for the NSP System occurred on July 29, 2008.

Because demand has dropped so significantly, and because this transmission project was designed as a whole to address Minnesota and regional conditions and claimed need, the need for the project must be reviewed in detail.

VI. The RUS EIS must address a range of system alternatives

B-019-010 The RUS EIS must address a wide range of system alternatives – the state improperly rejected alternatives if they could not, alone, address the presumed need. System alternatives include conservation, efficiency, SmartGrid distribution to level out load peaks, generalized load shifting, local generation (i.e., the planned Rochester West End gas plant, SE Minnesota wind generation), and siting of generation without new transmission, i.e., Minnesota's Distributed Renewable Generation Study.

The EPA submitted comments in another Minnesota docket, noting that that alternatives analysis was insufficient because the project was falsely limited to specific sites. This also applies to CapX, because in the case of CapX, the alternatives analysis was also falsely limited. Alternatives that were not deemed to be able, alone, to address all of the claimed needs of CapX, were rejected out of hand. After addressing the needs claimed by CapX applicants, the RUS must then take a closer look and address ability of various combinations of alternatives to address need. NoCapX & U-CAN Exhibit K, EPA letter regarding alternatives analysis in EIS for Mesaba Project, January 10, 2008.

VII. The RUS EIS must address property values

B-019-011 The RUS EIS must address property values, including compensation of affected landowners near, but not under the lines, for property devaluation and other costs. Landowners face property valuation costs such as loss of value and credit-worthiness from the day the project is announced, in addition to valuation losses in sales or decreased value in assessments which have an impact on local governments.

VIII. The RUS EIS must address impacts of EMF, including high frequency EMF

B-019-012 The RUS EIS must address impacts of EMF, specifically including high frequency EMF testing and modeling. EMF modeling and testing is too often only tested at 60hz. Higher frequencies, particularly very high frequencies, must be modeled, monitored and tested For more info: www.powerlinefacts.com

IX. The RUS EIS must address impacts of noice, particularly low frequency substation noise

B-019-010

Your comment has been noted. Alternatives to the project will be addressed in the Draft Environmental Impact Statement.

B-019-011

Your comment has been noted. Socioeconomic impacts to property values affected by the transmission line will be addressed in the Draft Environmental Impact Statement.

B-019-012

Your comment has been noted. Potential impacts to human and livestock health and safety with regard to EMF will be addressed in the Draft Environmental Impact Statement.

B-019-013 Noise of substations is particularly annoying, and low frequencies, below state of Minnesota standards, can be heard for long distances. Low frequency noises should be modeled and level should be taken at other similar substations for baseline purposes.

Thank you for the opportuity to submit these comments.

Very truly yours,

Carol A. Overland

Carol A. Overland
Attorney for NoCapX 2020 and United Citizens Action Network

B-019-013

Your comment has been noted. Potential impacts related to noise will be addressed in the Draft Environmental Impact Statement.

CapX 2020

A Vision for Transmission Infrastructure Investments for Minnesota

NoCapX & UCAN
Exhibit A

minnesota power

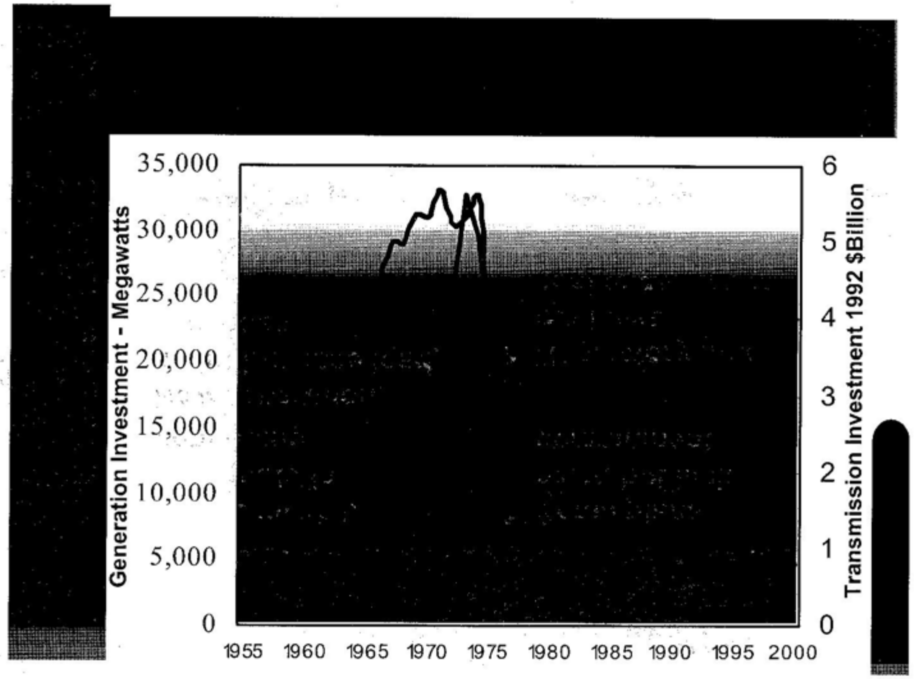
Xcel Energy

GREAT RIVER ENERGY

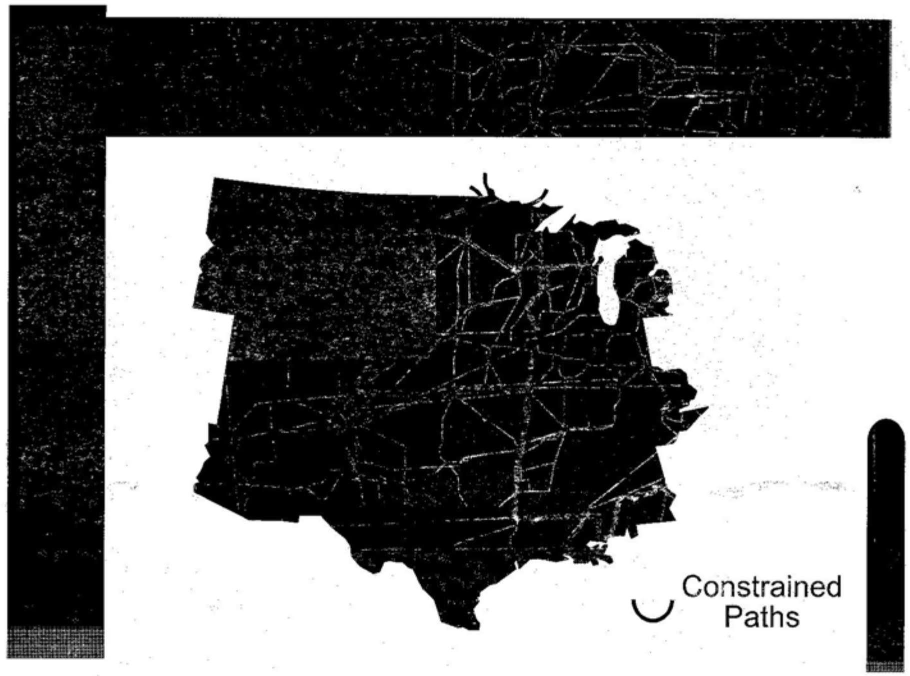
OTTER TAIL POWER COMPANY

- A long-range vision for transmission infrastructure investments for Minnesota
- Higher level of joint planning among transmission owners
- A planning study with a 15-year horizon
- It will put risk issues in focus for utilities, legislators, regulators and other stakeholders

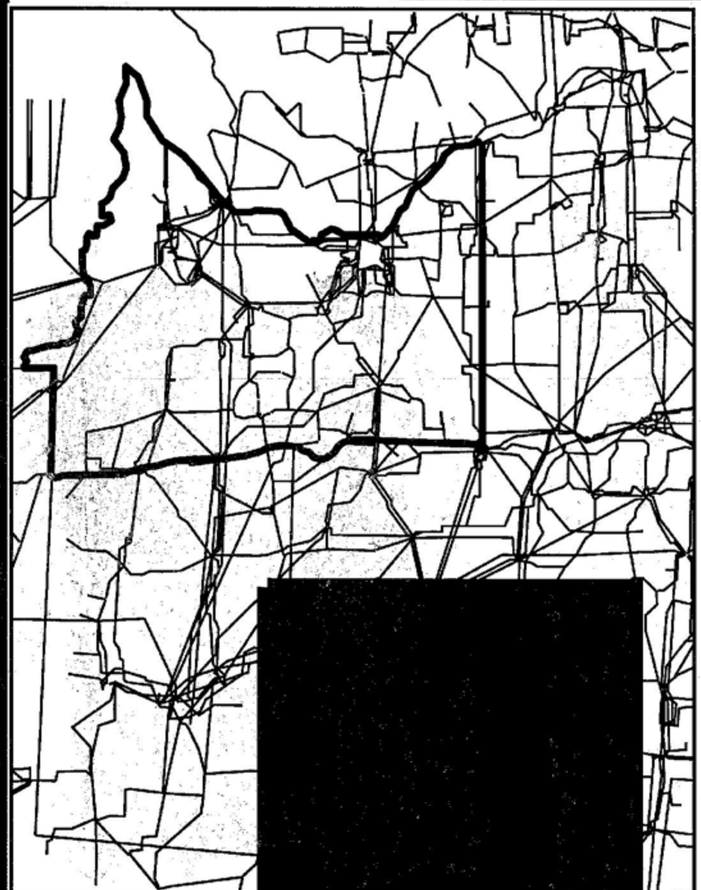
- Load growth in Minnesota is continuing
- New generation, including base load, is needed
- Major transmission projects are needed
- Some plans exist, but lack commitment
- Regulatory and business challenges must be addressed



35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Generation Investment - Megawatts
6
5
4
3
2
1
0
Transmission Investment 1992 $Billion
1955
1960
1965
1970
1975
1980
1985
1990
1995
2000


Constrained
Paths

[redacted]



[redacted]

- Intent is to meet growing electricity demand with high reliability
  - Geography defined by service territories, plus
  - Regional facilities for capacity and reliability that support load serving, plus
  - Generation transmission to serve load

- Will include new generation scenarios
- Will address transmission needs anticipated for Minnesota Renewable Energy Objective
- Will address issues related to achieving market efficiency
  - Congestion relief

- **Studies**
  - Upper Great Plains Transmission Coalition
    - Northwest Exploratory Study
  - Northern IA/Southern MN Exploratory Study
  - Red River Valley Transmission Improvement Planning Study (TIPS)
  - Dakota Wind Studies 2004 (WAPA)
  - MISO Baseline Reliability
- **Groups**
  - MISO
  - SPGs
  - MN State Transmission Plan

Stakeholder Input	**August 04- December 04**
Technical Studies	**September 04 – February 05**
Preliminary Report	**October 04**
Final Report	**March 05**

- **Load Levels**
  - **MAPP 2009 models with loads adjusted to 2020 levels based on MAPP Load and Capability Report**
- **Generation Levels**
  - **Known planned resource additions**
    - Buffalo Ridge Wind, Faribault, etc
  - **Resource planners**
    - Identify locations where they are studying
  - **Generation interconnection queue**
    - MISO
  - **Stakeholder input**

Task	Start	Finish
Develop scope	July 15	Aug. 15
Model development	Aug. 9	Sept. 1
Study analysis	Sept. 1	Feb. 15
Interim updates		Oct/Jan
Final report		March 1

- Move forward with scope development and model development
- Develop a plan to address business and public policy concerns
- Work with stakeholders to implement vision

- Great River Energy
  Gordon Pietsch
  763-241-2235
- Minnesota Power
  Mike Klopp
  218-720-2696
- Otter Tail Power
  Tim Rogelstad
  218-739-8583
- Xcel Energy
  Amanda King
  612-330-5931

Central Minnesota Municipal Power Agency

GREAT RIVER ENERGY

minnesota power

Minnkota Power COOPERATIVE, INC.

MISSOURI RIVER ENERGY SERVICES

OTTER TAIL POWER COMPANY

Southern Minnesota Municipal Power Agency

Xcel Energy

September 6, 2005

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East
St. Paul, MN 55101

Mr. Edward Garvey
Assistant Commissioner
Minnesota Department of Commerce
85 7th Place, Suite 500
St. Paul, MN 55101

Re: **CapX Project Group 1 Implementation Plan**

Dear Messrs. Haar and Garvey:

On behalf of the CapX 2020 participating utilities, I want to thank both of you and your agencies for the time and energy devoted to transmission issues, particularly during the recent legislative session. Those efforts have helped lay the groundwork for developing needed transmission infrastructure in the state, a critical component of our state's energy future.

As you know, the CapX 2020 utilities have worked to develop a long-term vision for transmission infrastructure to meet growing regional needs, and have made significant progress. We are now moving from the planning and study stage to implementation of Project Group 1. To ensure you are aware of our plans, which will result in regulatory filings in the near future, we wanted to provide you this update.

The information in this letter is general in nature and does not require either a docket or comment period; however, we are copying it to those on the service list the Commission maintains for the Biennial Transmission Projects Report to ensure that interested parties are likewise aware of our efforts.

Doc# 2050577.5

NoCapX & UCAN
Exhibit B

Background

Over the last year, transmission planners have worked to develop a comprehensive framework for much needed transmission infrastructure for the state of Minnesota. Instead of a piecemeal approach in which each individual electrical issue is studied and addressed separately, we endeavored to integrate our planning efforts and identify common improvements to the high voltage transmission system over a broad spectrum of possible futures.

Our effort focused on the growing demand for electricity in Minnesota over the next fifteen years, through the year 2020. We understand from resource planners at utilities serving customers in Minnesota and surrounding states that the demand for electricity could increase by roughly 6300 megawatts by around 2020. To deliver that much power, substantial improvements to the bulk power transmission system serving the state will be required. Even using lower growth estimates (e.g., 4,500 MW), our studies identify that a significant amount of backbone transmission infrastructure will be required.

We named this joint planning effort "CapX 2020" in recognition that substantial capital investments will be needed to meet electrical demand projections of the planning period. We published our draft plan in May, have been talking to parties, and refining it since. An overview and update was presented to the Commission and the Department on July 18, 2005.

Vision Study Overview

As noted in our preliminary study report and at the July presentation, our Vision Study, in conjunction with other regional transmission studies, has identified a number of significant transmission projects as necessary to meet anticipated load by 2020. The projects have been put into four different "groups," based generally on need, the amount and detail of study work performed to date, and coordination with other regional planning efforts. Listed below is Project Group 1, with expected CON filing and in-service dates.

Project Group 1		Expected CON Filing	Expected In-Service
Big Stone II Transmission	CapX West	3rd qtr 05	2011
Buffalo Ridge Outlet		4th qtr 05	2009
Buffalo Ridge – Metro 345		4th qtr 05	2010
Boswell – Wilton 230	CapX Northwest	1st qtr 06	2010
Fargo – Alexandria – Benton County 345		4th qtr 06	2012
Prairie Island – Rochester – LaCrosse 345	CapX Southeast	1st qtr 06	2011

Projects in the other three groups were listed in the July presentation. Further study work and detailed analysis on these projects is ongoing.

Doc# 20505775

Near-Term Actions

To move these study results to project proposals, the CapX utilities have been working to prepare regulatory filings for Project Group 1. We intend to make a number of regulatory filings in the coming months seeking approvals to build three major 345 kV components of our plan. In those filings, we will continue to emphasize that projects should not be viewed in isolation but as parts of an integrated whole needed to meet both regional and local reliability needs. Toward that end we intend to be presenting our plans in more detail as part of the November 1 Minnesota Transmission Planning Report. However, you will see filings before then to get the regulatory process started for a number of elements of the plan.

The initial three regional solutions to be proposed through Certificate of Need filings and routing applications are:

- **CapX West** consists of several projects including a new 345 kV line connecting western Minnesota and the Twin Cities, an upgrade of a 115 kV line from Big Stone to Morris to a 230 kV line and two new 115 kV lines in the Buffalo Ridge area. These projects have been closely coordinated with Big Stone generation interconnection requests and Buffalo Ridge transmission requirements.
- CapX **Northwest** consists of a 345 kV line between the Fargo and St. Cloud and a 230 kV line from Bemidji to the Grand Rapids area. These lines will establish a second new spoke in the bulk power expansion plan while also providing reliability upgrades in the Red River Valley and the St. Cloud areas. Combined, these first two elements of our plan will complete the key western Minnesota components of the Vision Study.
- CapX **Southeast** is a 345 kV line connecting the high voltage system in Red Wing to Rochester and the La Crosse area. This project will provide another spoke in the bulk power system and provide support for growing electrical demand in communities in southeastern Minnesota.

Additional description of each of these near-term actions is provided below.

CapX West

The first element to be presented for certificate of need approvals will be transmission facilities associated with the Big Stone generation project. While the Big Stone II partners include some non-CapX members, those of us responsible for transmission associated with Big Stone II have been working closely with the rest of the CapX members and with MISO. As was outlined in the Big Stone notice plan, MISO interconnection studies show that a second unit at Big Stone requires a minimum of two 230 kV interconnection lines. The Big Stone partners now intend to propose constructing the line connecting Big Stone and Granite Falls to 345 kV standards to better meet and be integrated with CapX, state, and regional objectives. As a result, the Big Stone transmission project, in addition to providing interconnection facilities for a

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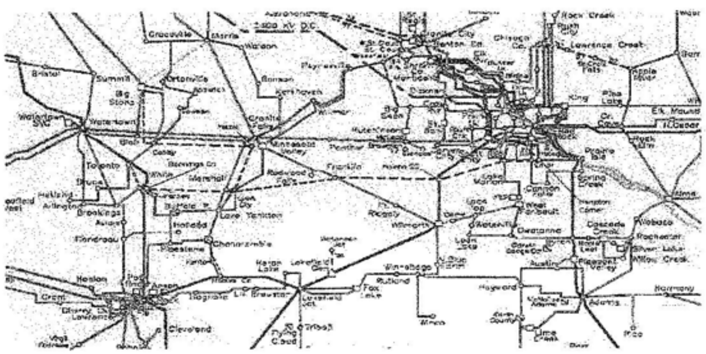
Messrs. Haar and Garvey
September 6, 2005
Page 4

second unit at Big Stone, is now being planned as the first phase of a 345 kV line between southwestern Minnesota and the Twin Cities metro area. The Big Stone transmission partners expect to file a certificate of need for these facilities in September.

Next we intend to file for approval of the rest of the components of CapX West, which consist of 345 kV lines connecting substations near Brookings, Marshall, and Granite Falls to the bulk power supply system in the southern part of the Twin Cities area. The 345 kV plan is needed to meet the growing demand for electricity under a number of future power demand and generation scenarios. It also strengthens system reliability in parts of western and south central Minnesota. Our application will also include the 115 kV lines necessary to increase power delivery capability from the Buffalo Ridge area.

CapX and other utilities are now conducting the detailed studies to provide the design information required for certificate of need filings and are actively sorting out proposed ownership and other implementation details. We anticipate making a notice plan filing in September and a certificate of need application as soon thereafter as the process allows, likely in November or December.

We believe that when viewed as an integrated package, these projects establish one of the key spokes in the overall plan for enhanced transmission infrastructure for the southwestern and western parts of the state. A simple schematic of the project on an integrated basis is provided below.



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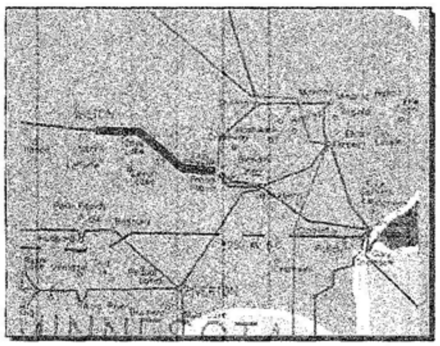
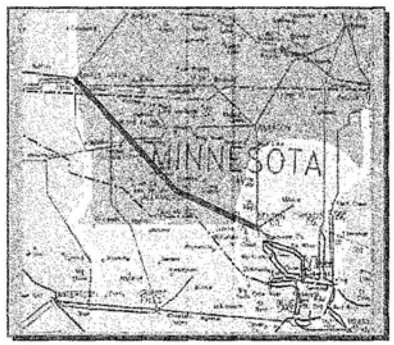
CapX Northwest

The next component of the overall implementation plan is a 345 kV transmission line between the Red River Valley and St. Cloud, the northern terminus of the 345 kV system surrounding the Twin Cities. Studies demonstrate that this line would support a number of possible statewide electrical growth scenarios and address identified electrical reliability issues in the Red River Valley and the St Cloud area. This element of the CapX plan also acts in concert with CapX West to efficiently deliver power from western Minnesota where interest in renewables based generation is high. Studies have also identified the need for a 230 kV line connecting the Grand Rapids and Bemidji areas (Boswell-Wilton project). We plan to make notice plan filings and certificate of need applications for these facilities likely sometime in the first quarter of 2006 for the Boswell-Wilton 230 kV project and later in 2006 for the Red River Valley-Benton County 345 kV project.

Schematics of these projects are also presented below.





CapX Southeast

A third element of the near-term CapX plan is a proposal for a 345 kV addition between Prairie Island, Rochester and the La Crosse, Wisconsin area. Studies have shown the need for a large infrastructure addition in this area. A 345 kV facility will provide a third spoke into western Wisconsin and form the likely interconnection with a new 345 kV LaCrosse – Columbia, Wisconsin facility being considered by the American Transmission Company. We are working with ATC and at this point anticipate making a notice plan filing in January or February 2006 and a certificate of need application as soon as possible thereafter.

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A schematic of that project is provided below (the red-dotted line indicates CapX facilities: the blue line identifies ATC facilities).

Conclusion

As CapX 2020 utilities, we are committed to continuing to work cooperatively to bring these projects to fruition. We are currently working to prepare the regulatory filings to move these projects from the study phase to the proposal phase, and ultimately to construction and completion. We are on an aggressive timeline, but also recognize our burden in proving the need for these facilities and will work within all regulatory processes to complete these proceedings. In doing so, however, we will continue to refer back to the backbone studies that identified these critical common elements to Minnesota's energy future. We appreciate your consideration of that information, and hope it is useful to you as you plan upcoming workload. As always, we are willing to work with interested parties in providing needed information as these filings proceed.

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Feel free to contact either me or any of the below CapX 2020 utilities' representatives if you have any questions or require any additional information regarding this letter or our plans for upcoming filings. I can be reached at (763) 241-2380.

Very truly yours,

William R. Kaul
Vice President, Transmission
Great River Energy
On Behalf of the Cap-X Utilities

c: Donald Jones, Xcel Energy
Tom Ferguson, Minnesota Power
Rod Scheel, Otter Tail Power Company
Ray Wahle, Missouri River Energy Services
Donald Kom, Central Minnesota Municipal Power agency
David Geschwind, Southern Minnesota Municipal Power Agency
Al Tschepen, Minnkota Power Cooperative

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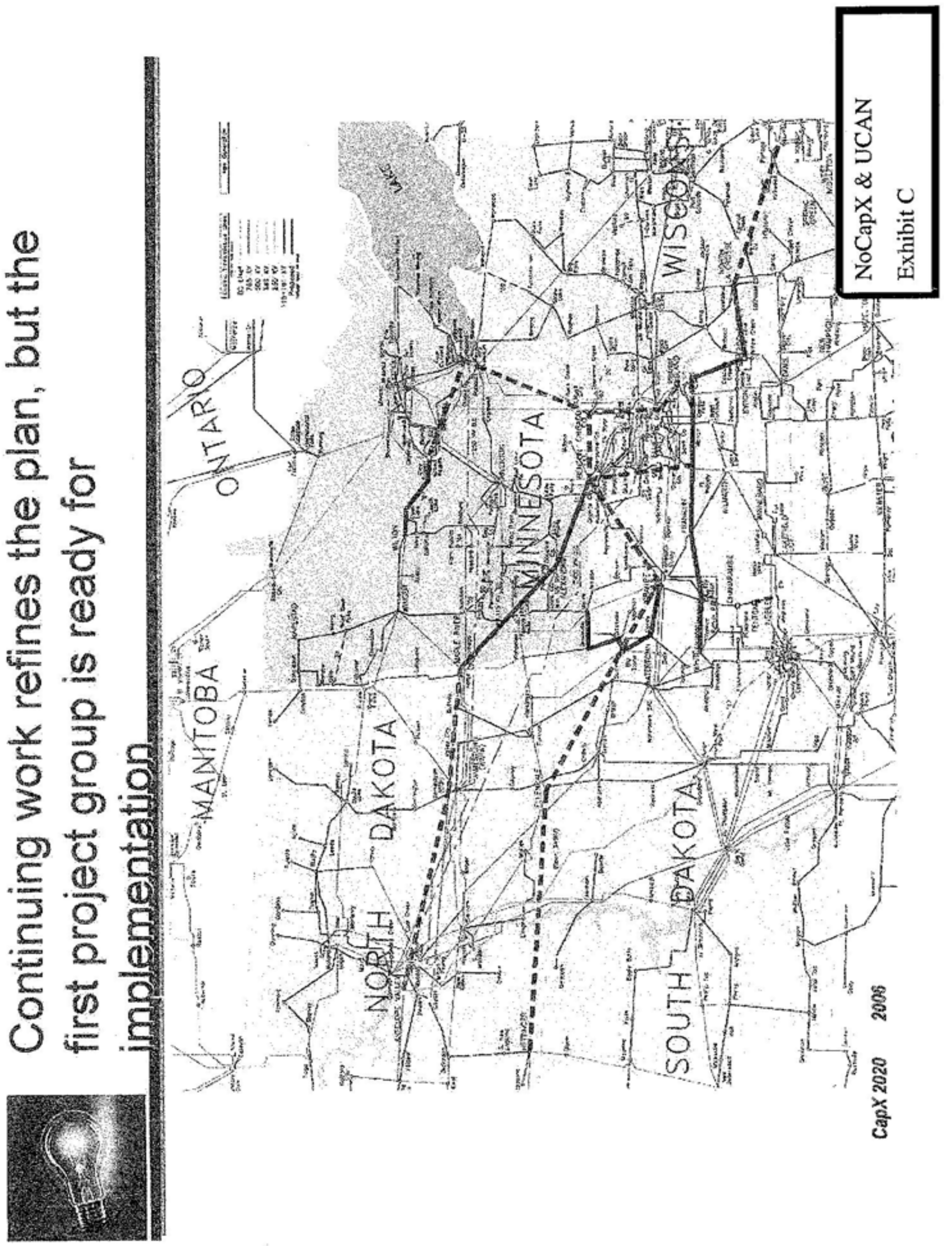

Continuing work refines the plan, but the first project group is ready for implementation
NoCapX & UCAN
Exhibit C
ONTARIO
MANITOBA
NORTH DAKOTA
MINNESOTA
SOUTH DAKOTA
CapX 2020
2006

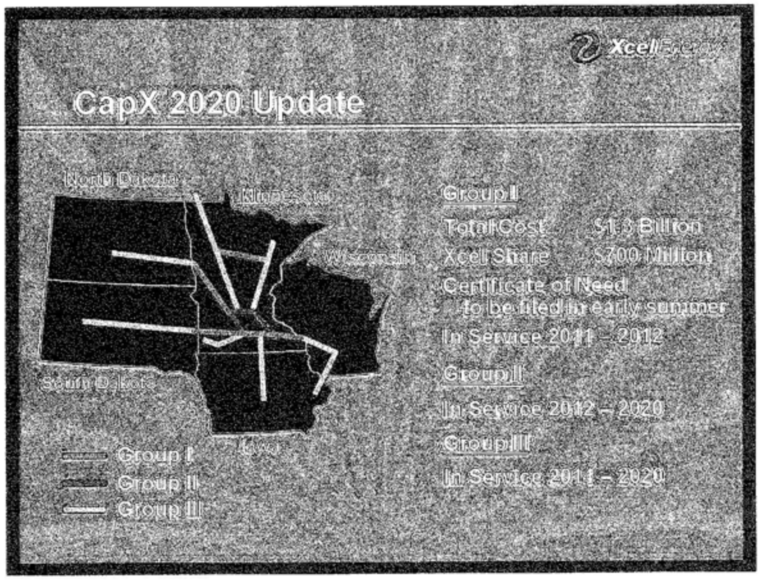
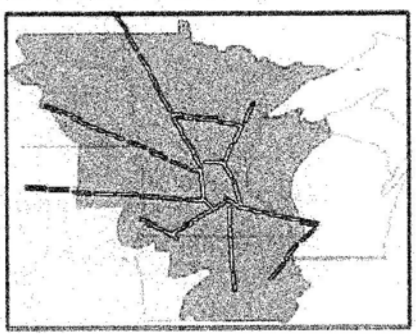


Figure 1-9: Geographic Scope of CapX2020



NoCapX & UCAN

Exhibit D

THIS IS CAPX 2020

CapX 2020 is so much more than just the "Hampton – LaCrosse" line!

Table 4. Summary of Vision Plan

Facility Name				
From	**To**	**V olt (kV)**	**Miles**	**Cost ($M)**
Alexandria, MN	Benton County (St. Cloud, MN)	345	80	60
Alexandria, MN	Maple River (Fargo, ND)	345	126	94.5
Antelope Valley (Beulah, ND)	Jamestown, ND	345	185	138.75
Arrowhead (Duluth, MN)	Chisago County (Chisago City, MN)	345	120	90
Arrowhead (Duluth, MN)	Forbes (Northwest Duluth, MN)	345	60	45
Benton County (St.Cloud, MN)	Chisago County (Chisago City, MN)	345	59	44.25
Benton County (St. Cloud, MN)	Granite Falls, MN	345	110	82.5
Benton County (St. Cloud, MN)	St. Bonifacius, MN	345	62	45.5
Blue Lake (Southwest Twin Cities, MN)	Ellendale, ND	345	200	150
Chisago County (Chisago City, MN)	Prairie Island (Red Wing, MN)	345	82	61.5
Columbia, WI	North LaCrosse, WI	345	80	60
Ellendale, ND	Hettinger, ND	345	231	173.25
Rochester, MN	North LaCrosse, WI	345	60	45
Jamestown, ND	Maple River (Fargo, ND)	345	107	80.25
Prairie Island (Red Wing, MN	Rochester, MN	345	58	43.5
TOTAL			**1620**	**$1,215 ($M)**

Exhibit 17, Portion of the 2005 Biennial Report Filed by Transmission Utilities, p. 36; Ex. 1, Application, App. A-1, Technical Update October 2005; see also Exhibit 12, CapX 2020 Update, June 14, 2006; Rogelstad, Vol. 2A, p. 69-74; Rogelstad, Direct Testimony p. 17; Rogelstad, Tr. Vol 2A, p. 39 et seq.

NoCapX & UCAN

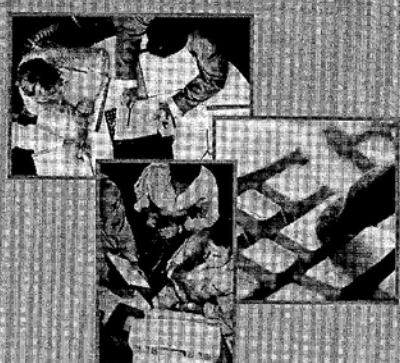
Exhibit E

February 28, 2007

ICF INTERNATIONAL

Independent Assessment of Midwest ISO Operational Benefits

Submitted to:
Midwest ISO



Submitted by:
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NoCapX & UCAN
Exhibit G

Table of Contents

List of Exhibits

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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.

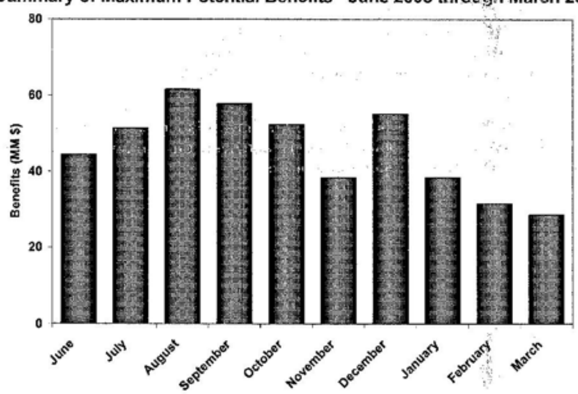
In each of the three cases the system production costs comprise the hourly fuel, variable operation and maintainence, NO_x emission allowance, and SO_2 emission allowance costs of every generator in the US Eastern Interconnect[8].

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

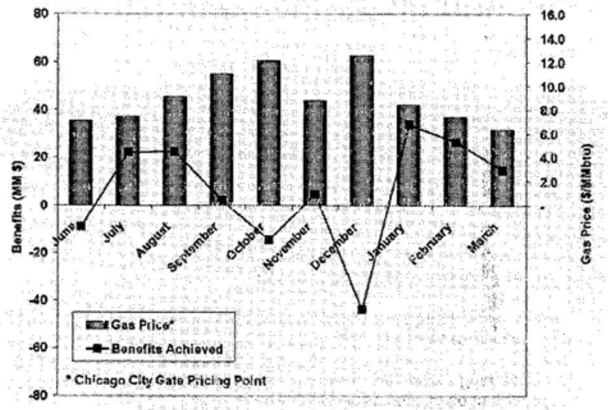
Our analysis yields the following three primary results:

- 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.

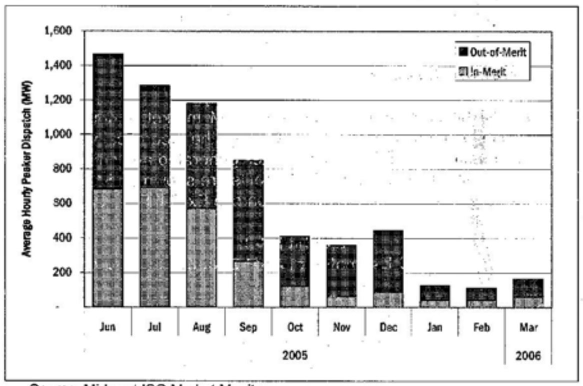
[10] Source: Gas Daily; Chicago City Gate price

[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.

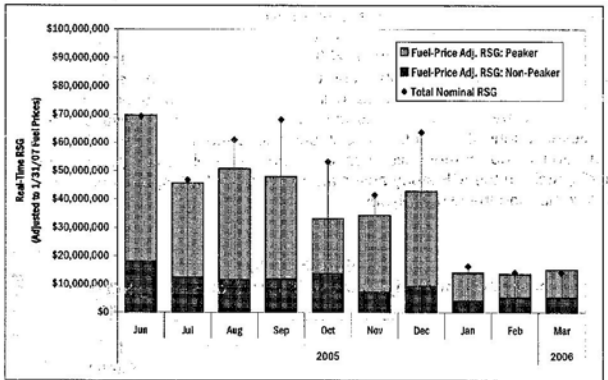
Exhibit ES-6:
Market Monitor Analysis of the Dispatch of Peaking Resources



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.

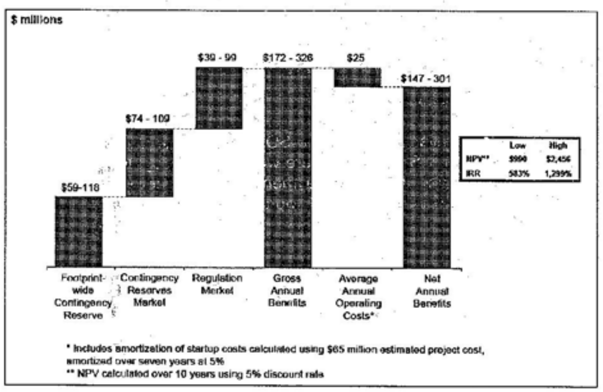
Exhibit ES-7:
Market Monitor Analysis of the Midwest ISO RSG Payments



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.

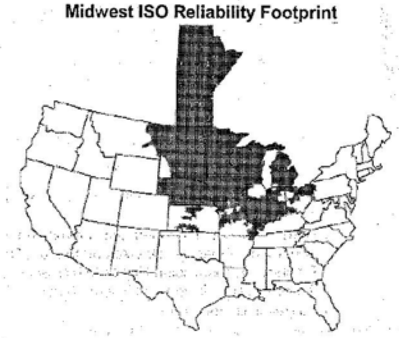
Regional Overview of the Midwest ISO[12]

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

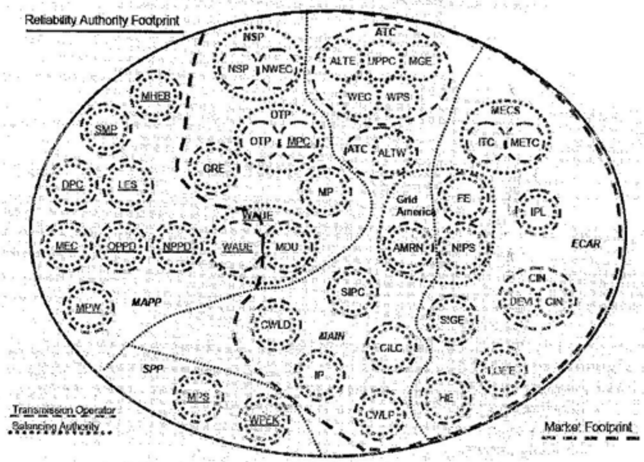
Metric	Parameter
Territory	920,000 square miles covering 15 US states and Canadian province of Manitoba. Control centers in Carmel, IN and St. Paul, MN
Market Participants	256 including 28 Transmission Owners with $13.9 billion in transmission assets under the Midwest ISO's functional control and 69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



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

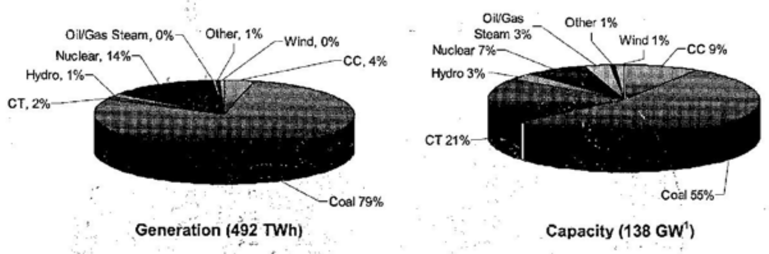
Source: Midwest ISO Business Practices Manual for Coordinated Reliability, Dispatch, & Control, Manual No. 006, 2005. Note that GridAmerica and ATC are no longer operational but the Balancing Authorities pictured are valid up to the end of the study period in March 2006. Since then, DEVI and LGEE are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

Midwest ISO Supply Mix

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

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

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



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.

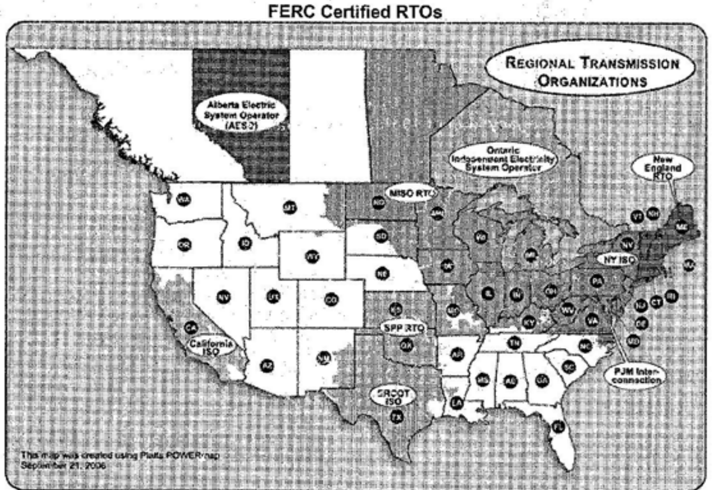
Midwest ISO's Interconnectivity with the Rest of the Grid

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

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[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.

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[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.

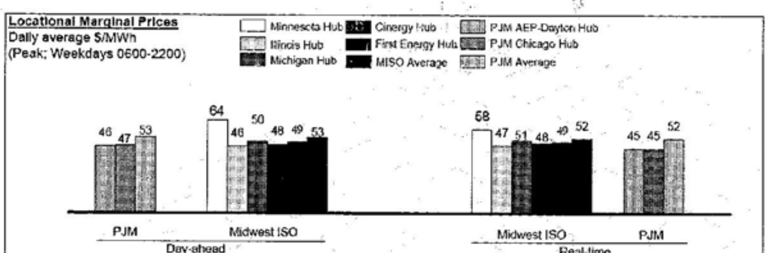
The Midwest ISO publishes a day-ahead schedule and a 24-hour day-ahead set of LMPs. The day-ahead schedules constitute financial contracts to supply or consume power. FTRs are also settled based upon the 24-hour day-ahead LMP values.

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:

- <u>Day-1 Case</u>: 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.

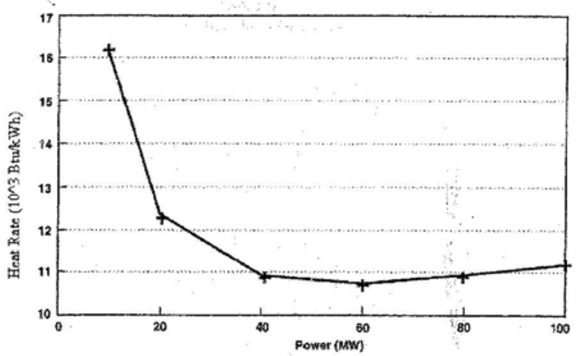
We discuss the approach used to estimate each of these two cost components for the Day-2 Actual Case below.

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:

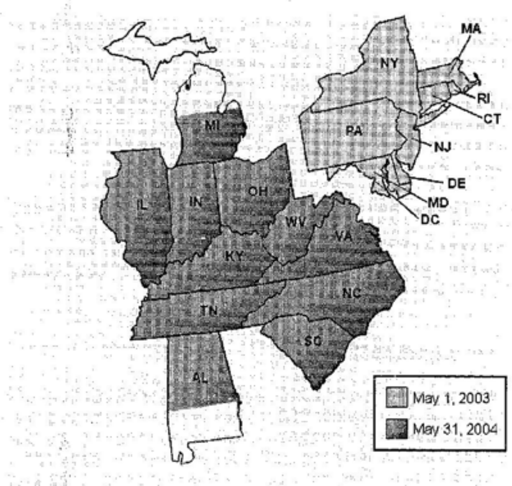
*$4.00/MWh * 30 MW = $120/hr in VOM costs*

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.

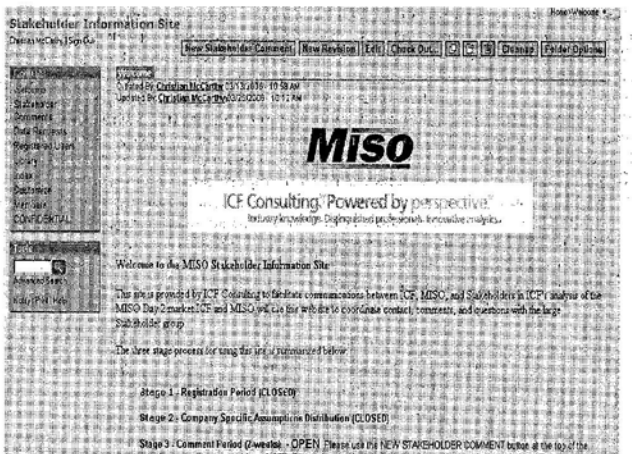
Stakeholder Participation Process

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.

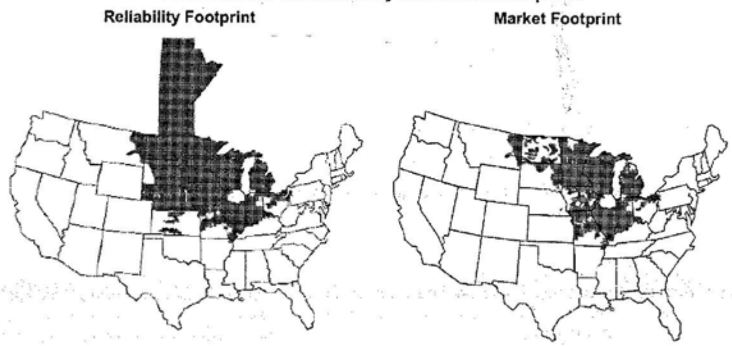
Exhibit 3-1:
Data and Source for Modeling Assumptions

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.

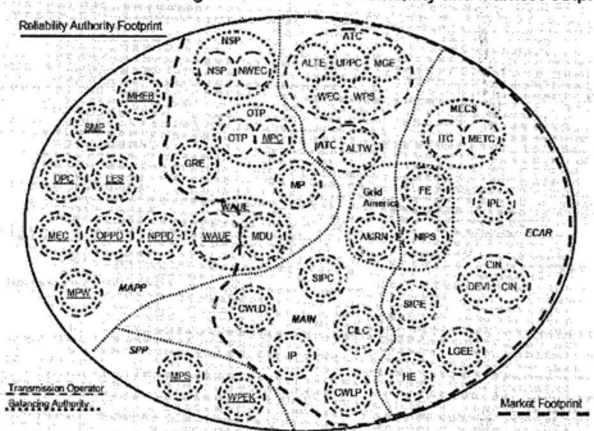
[44] DEVI and CIN are aggregated in this analysis

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



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).

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Supply-Side Assumptions

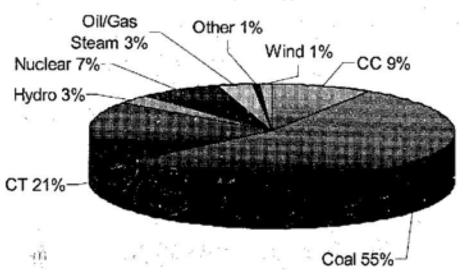
This section focuses on the key supply-side assumptions underlying the analysis. These include the following 5 broad categories:

- 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.

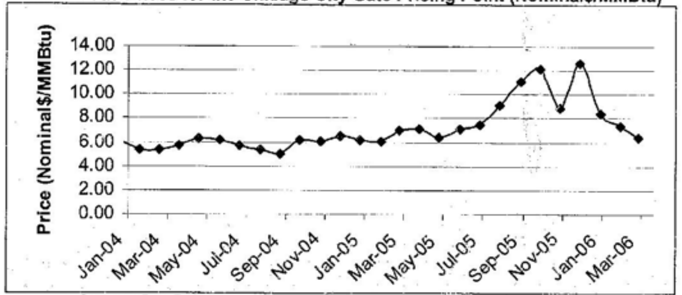
Unit Outages and Derates

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

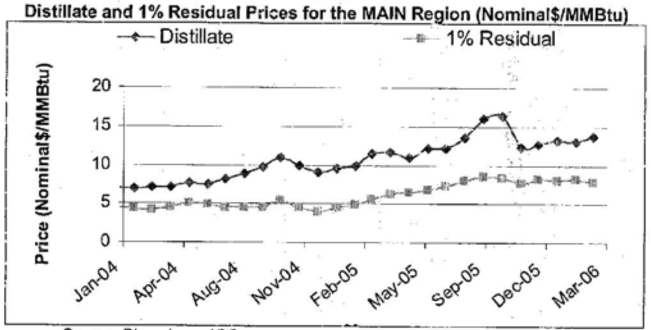
Month-Year	ECAR[1]	ECAR-KY[2]	ECAR-MECS[3]	MAIN-ILMO[4]	MAIN-WUMS[5]	MAPP[6]
Jan-04	6.34	7.91	6.01	6.11	6.09	6.00
Feb-04	5.64	5.92	5.48	5.39	5.40	5.24
Mar-04	5.61	5.67	5.58	5.42	5.43	5.11
Apr-04	5.98	6.03	5.96	5.72	5.73	5.36
May-04	6.55	6.65	6.51	6.31	6.32	5.92
Jun-04	6.56	6.59	6.41	6.20	6.22	5.85
Jul-04	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

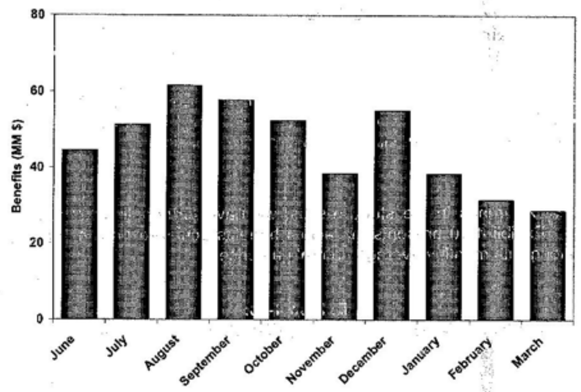
ICF used historical delivered oil prices during the study period for this analysis. The delivered oil price is a sum of the actual WTI monthly crude price from Bloomberg and estimated transportation differentials developed by ICF. Oil prices, most noticeably distillate oil prices, also increased significantly 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 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

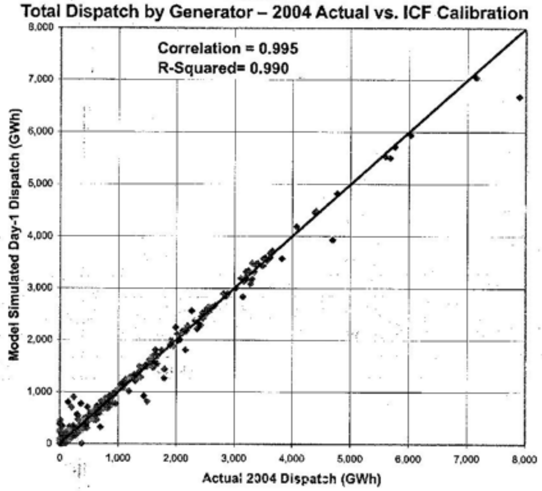
Category	Benefits ($million)	Annualized Benefits ($million)
Theoretical Maximum Potential Benefits	460	552
Estimated Achievable Benefits Given Current Market Structure	271	325
Actual Benefits Achieved	58	70

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

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



Source: ICF

Study Findings

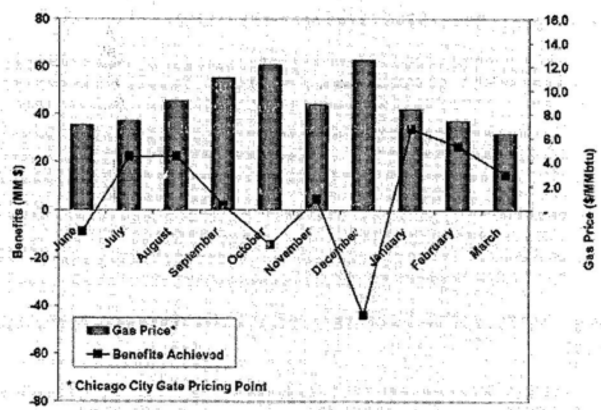
Results of the ICF study indicate that the Day-2 market within the Midwest ISO footprint offers the potential for significant savings. Specifically, production cost savings of $460 million were estimated as the maximum benefits available to the Midwest ISO in an optimally operated Day-2 market including 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.

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.

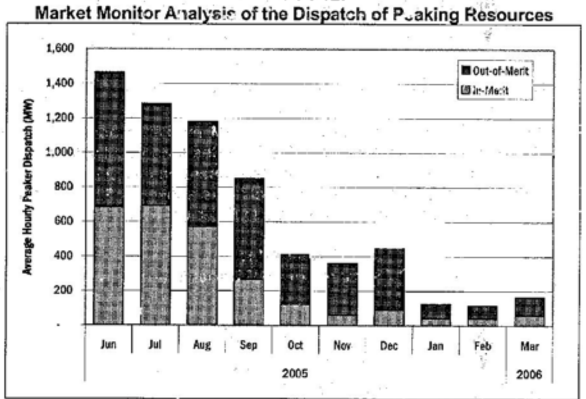
- **Choice of Calibration Year** – As discussed in Chapter 2, ICF, in consultation with the Study Steering Committee, chose 2004 as the calibration year due to data availability. During the review process, several stakeholders noted that 2004 was not an "average" year within the Midwest ISO footprint. 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.

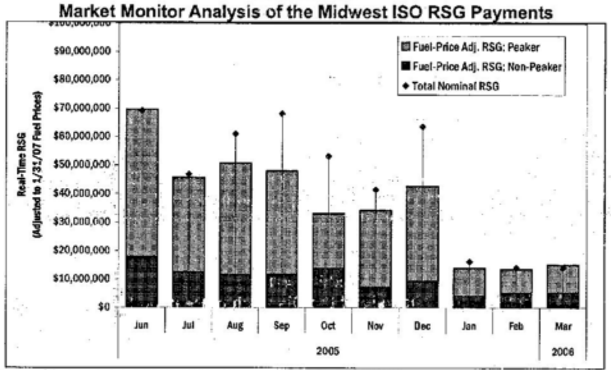
Exhibit 4-12:
Market Monitor Analysis of the Dispatch of Peaking Resources



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.

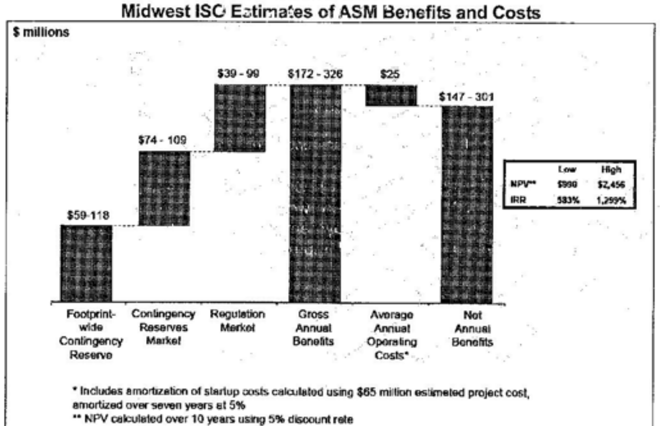
Exhibit 4-13:
Market Monitor Analysis of the Midwest ISO RSG Payments



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.

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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. instantaneou s 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)

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EXHIBIT A

http://online.wsj.com/article/SB122722654497346099.html

Surprise Drop in Power Use Delivers Jolt to Utilities

November 21, 2008

By REBECCA SMITH

An unexpected drop in U.S. electricity consumption has utility companies worried that the trend isn't a byproduct of the economic downturn, and could reflect a permanent shift in consumption that will require sweeping change in their industry.

Numbers are trickling in from several large utilities that show shrinking power use by households and businesses in pockets across the country. Utilities have long counted on sales growth of 1% to 2% annually in the U.S., and they created complex operating and expansion plans to meet the needs of a growing population.

"We're in a period where growth is going to be challenged," says Jim Rogers, chief executive of Duke Energy Corp. in Charlotte, N.C.

The data are early and incomplete, but if the trend persists, it could ripple through companies' earnings and compel major changes in the way utilities run their businesses. Utilities are expected to invest $1.5 trillion to $2 trillion by 2030 to modernize their electric systems and meet future needs, according to an industry-funded study by the Brattle Group. However, if electricity demand is flat or even declining, utilities must either make significant adjustments to their investment plans or run the risk of building too much capacity. That could end up burdening customers and shareholders with needless expenses.

To be sure, electricity use fluctuates with the economy and population trends. But what has executives stumped is that recent shifts appear larger than others seen previously, and they can't easily be explained by weather fluctuations. They have also penetrated the most stable group of consumers -- households.

Dick Kelly, chief executive of Xcel Energy Inc., Minneapolis, says his company, which has utilities in Colorado and Minnesota, saw home-energy use drop 3% in the period from August through September, "the first time in 40 years I've seen a decline in sales" to homes. He doesn't think foreclosures are responsible for the trend.

Duke Energy Corp.'s third-quarter electricity sales were down 5.9% in the Midwest from the year earlier, including a 9% drop among residential customers. At its utilities operating in the Carolinas, sales were down 4.3% for the three-month period ending Sept. 30 from a year earlier.

NoCapX & UCAN

Exhibit H

American Electric Power Co., which owns utilities operating in 11 states, saw total electricity consumption drop 3.3% in the same period from the prior year. Among residential customers, the drop was 7.2%. However, milder weather played a role.

Utility executives question whether the recent declines are primarily a function of the broader economic downturn. If that's the case, says Xcel's Mr. Kelly, then utilities should continue to build power plants, "because when we come out of the recession, demand could pick up sharply" as consumers begin to splurge again on items like big-screen televisions and other gadgets.

Some feel that the drop heralds a broader change for the industry. Mr. Rogers of Duke Energy says that even in places "where prices were flat to declining," his company still saw lower consumption. "Something fundamental is going on," he says.

Michael Morris, the chief executive of AEP, one of the country's largest utilities, says he thinks the industry should to be wary about breaking ground on expensive new projects. "The message is: be cautious about what you build because you may not have the demand" to justify the expense, he says.

Utilities are taking steps to get a better understanding of the cause. Some are asking customers who reduced usage to explain what is influencing them. Xcel and other utilities, for example, have been running environmentally focused campaigns to urge consumers to use less energy recently, a message that might be taking hold.

Power companies are also questioning the reliability of the weather-adjustment models they use to harmonize fluctuating sales from quarter to quarter. "It's more art than science," says Bill Johnson, Chief Executive of Progress Energy Inc., Raleigh, N.C.

If the sector is entering a period of lower demand -- which could accelerate further if the automotive sector collapses -- many utilities will have to change the way they cover their costs.

Utilities are taking a hard look at the way they set rates and generate profits. Many companies are embracing a new rate design based on "decoupling," in which they set prices aimed at covering the basic costs of delivery, with sales above that level being gravy. Regulators have resisted the change in some places, because it typically means that consumers using little energy pay somewhat higher rates.

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Xcel Energy

414 Nicollet Mall
Minneapolis, MN 55401

January 29, 2009

INVESTOR RELATIONS EARNINGS RELEASE

2008 YEAR END SUMMARY

- GAAP (generally accepted accounting principles) earnings were $646 million, or $1.46 per diluted share in 2008, compared with $577 million, or $1.35 per diluted share, in 2007.
- Ongoing diluted earnings per share were $1.45 in 2008, compared with $1.43 per share in 2007.
- 2008 ongoing earnings of $1.45 were within Xcel Energy's stated guidance range of $1.45 to $1.50 per share
- Xcel Energy reaffirms its 2009 earnings guidance of $1.45 to $1.55 per diluted share.

MINNEAPOLIS – Xcel Energy Inc. (NYSE: XEL) today reported 2008 GAAP earnings of $646 million, or $1.46 per share, compared with $577 million, or $1.35 per share, in 2007. Ongoing earnings, adjusted for certain non-recurring items, were $1.45 per share in 2008, compared with $1.43 per share in 2007.

Ongoing earnings for 2008 were slightly higher than last year primarily due to higher electric and natural gas margins, reflecting various increases in base rates and rider recovery and AFUDC-equity earnings. The impact of electric and natural gas margins was partially offset by the negative impact of weather when comparing the periods. Partially offsetting these positive factors were higher depreciation, interest expense and dilution.

GAAP earnings for 2008 earnings were higher than last year, primarily due to a 2007 charge associated with the resolution of a corporate-owned life insurance (COLI) dispute with the Internal Revenue Service (IRS).

"Overall, 2008 was a challenging year due to the global financial crisis and economic downturn. However, we successfully managed through the credit and liquidity crisis by issuing over $2 billion of debt and equity prior to the market collapse. As a result, we believe we are well positioned to implement our strategy of investing in our utility business. In addition, while our ongoing earnings were lower than we originally anticipated, we were pleased to deliver results within our 2008 guidance range," said Richard C. Kelly, chairman, president and chief executive officer. "At this time, we are reaffirming our 2009 earnings guidance of $1.45 to $1.55 per diluted share."

Earnings Adjusted for Certain Non-recurring Items (Ongoing Earnings - Note 7)

During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. Excluding the impact of the COLI program, Xcel Energy's ongoing 2008 earnings were $641 million, or $1.45 per share, compared with 2007 ongoing earnings of $612 million or $1.43 per share. The following table provides a reconciliation of GAAP earnings per share to ongoing earnings per share for 2008 and 2007:

	Three months ended Dec. 31,		Twelve months ended Dec. 31,	
Diluted earnings (loss) per share	2008	2007	2008	2007
Ongoing earnings per share	$ 0.35	$ 0.30	$ 1.45	$ 1.43
PSR Investments Inc. (PSRI)/COLI IRS settlement	0.01	0.01	0.01	(0.08)
GAAP earnings per share	$ 0.36	$ 0.31	$ 1.46	$ 1.35

NoCapX & UCAN
Exhibit I

At 10 a.m. CST today, Xcel Energy will host a conference call to review financial results. To participate in the call, please dial in five to 10 minutes prior to the start and follow the operator's instructions.

US Dial-In:	(800) 218-0713
International Dial-In:	(303) 228-2960

The conference call also will be simultaneously broadcast and archived on Xcel Energy's Web site at www.xcelenergy.com. To access the presentation, click on Investor Information. If you are unable to participate in the live event, the call will be available for replay from 1 p.m. CST on January 29 through 11:59 p.m. CST on January 31.

Replay Numbers

US Dial-In:	(800) 405-2236
International Dial-In:	(303) 590-3000
Access Code:	11123303#

Except for the historical statements contained in this release, the matters discussed herein, including our 2009 full year EPS guidance and assumptions, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Risk Factors in Item 1A and Exhibit 99.01 of Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2007.

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Xcel Energy Internet address: www.xcelenergy.com

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (Unaudited)

(Amounts in Thousands, Except Per Share Data)	Three Months Ended Dec. 31, 2008	Three Months Ended Dec. 31, 2007	Twelve Months Ended Dec. 31, 2008	Twelve Months Ended Dec. 31, 2007
Operating revenues				
Electric	$ 1,978,829	$ 1,912,961	$ 8,682,993	$ 7,847,992
Natural gas	706,287	669,281	2,442,988	2,111,732
Other	22,457	20,977	77,175	74,446
Total operating revenues	2,707,573	2,603,219	11,203,156	10,034,170
Operating expenses				
Electric fuel and purchased power	1,076,542	1,023,680	4,947,979	4,136,994
Cost of natural gas sold and transported	533,968	498,021	1,832,699	1,547,622
Cost of sales — other	6,987	10,191	21,082	24,370
Other operating and maintenance expenses	437,571	487,146	1,777,933	1,788,885
Conservation and demand-side management program expenses	25,435	25,754	117,713	101,772
Depreciation and amortization	205,867	202,200	828,379	805,731
Taxes (other than income taxes)	68,360	67,286	286,580	277,723
Total operating expenses	2,354,730	2,314,278	9,812,365	8,683,097
Operating income	352,843	288,941	1,390,791	1,351,073
Interest and other income, net	14,871	7,778	43,977	10,948
Allowance for funds used during construction - equity	18,041	11,913	63,519	37,207
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,096, $4,891, $20,390 and $21,410, respectively	147,248	129,610	552,919	520,037
Interest and penalties related to COLI settlement	—	—	—	43,401
Allowance for funds used during construction - debt	(10,290)	(10,464)	(39,038)	(34,593)
Total interest charges and financing costs	136,958	119,146	513,881	528,845
Income from continuing operations before income taxes	248,797	189,486	984,406	870,383
Income taxes	85,240	54,517	338,686	294,484
Income from continuing operations	163,557	134,969	645,720	575,899
Income (loss) from discontinued operations, net of tax	518	(927)	(166)	1,449
Net income	164,075	134,042	645,554	577,348
Dividend requirements on preferred stock	1,060	1,060	4,241	4,241
Earnings available to common shareholders	$ 163,015	$ 132,982	$ 641,313	$ 573,107
Weighted average common shares outstanding				
Basic	451,748	423,806	437,054	416,139
Diluted	455,174	434,009	441,813	433,131
Earnings per share — basic				
Income from continuing operations	$ 0.36	$ 0.31	$ 1.47	$ 1.38
Income from discontinued operations	—	—	—	—
Earnings per share — basic	$ 0.36	$ 0.31	$ 1.47	$ 1.38
Earnings per share — diluted				
Income from continuing operations	$ 0.36	$ 0.31	$ 1.46	$ 1.35
Income from discontinued operations	—	—	—	—
Earnings per share — diluted	$ 0.36	$ 0.31	$ 1.46	$ 1.35
Cash dividends declared per common share	$ 0.24	$ 0.23	$ 0.94	$ 0.91

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Investor Relations Release (Unaudited)

Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

Note 1. Earnings per Share Summary

The following table summarizes the diluted earnings per share contributions of Xcel Energy's businesses:

Diluted earnings (loss) per share	Three months ended Dec. 31, 2008	Three months ended Dec. 31, 2007	Twelve months ended Dec. 31, 2008	Twelve months ended Dec. 31, 2007
Regulated utility — continuing operations (Note 2)	$ 0.38	$ 0.33	$ 1.59	$ 1.55
Holding company and other costs	(0.03)	(0.03)	(0.14)	(0.12)
Ongoing earnings per share	0.35	0.30	1.45	1.43
PSRI/COLI IRS settlement (Note 7)	0.01	0.01	0.01	(0.08)
Total diluted earnings per share	$ 0.36	$ 0.31	$ 1.46	$ 1.35

The following table summarizes significant components contributing to the changes in the three- and twelve- month periods ended Dec. 31, 2008 diluted earnings per share, compared with the same periods in 2007, which are discussed in more detail later in this release.

	Three months ended Dec. 31,	Twelve months ended Dec. 31,
2007 GAAP earnings per share	$ 0.31	$ 1.35
PSRI/COLI IRS settlement	(0.01)	0.08
2007 ongoing earnings per share	0.30	1.43
Components of change — 2008 vs. 2007		
Lower operating and maintenance expenses	0.07	0.02
Higher electric margins	0.02	0.03
Higher natural gas margins	—	0.06
Higher allowance for funds used during construction – equity	0.01	0.06
Higher depreciation and amortization	—	(0.03)
Higher conservation and demand-side management program expenses	—	(0.02)
Higher financing costs	(0.03)	(0.05)
Dilution from common equity issuance, DRIP and benefit plans	(0.02)	(0.03)
Other	0.01	(0.01)
2008 GAAP earnings per share	0.36	1.46
2008 PSRI/COLI IRS settlement	(0.01)	(0.01)
2008 ongoing earnings per share	$ 0.35	$ 1.45

Note 2. Regulated Utility Results — Continuing Operations

Estimated Impact of Temperature Changes on Earnings — The following table summarizes the estimated impact of temperature variations on results, compared with sales under normal weather conditions.

	Three months ended Dec. 31, 2008 vs. Normal	Three months ended Dec. 31, 2007 vs. Normal	Three months ended Dec. 31, 2008 vs. 2007	Twelve months ended Dec. 31, 2008 vs. Normal	Twelve months ended Dec. 31, 2007 vs. Normal	Twelve months ended Dec. 31, 2008 vs. 2007
Retail electric	$ 0.00	$ 0.00	$ 0.00	$ (0.01)	$ 0.06	$ (0.07)
Firm natural gas	0.00	0.00	0.00	0.01	0.00	0.01
Total	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.06	$ (0.06)

Sales Growth — The following table summarizes Xcel Energy's regulated sales growth for actual and weather-normalized energy sales for the three- and twelve-month periods ended Dec. 31, 2008, compared with the same periods in 2007. The year-end sales growth amounts for 2008 have been adjusted for leap year.

	Three months ended Dec. 31,		Twelve months ended Dec. 31,	
	Actual	Normalized	Actual	Normalized
Electric residential	0.2%	0.2%	(2.0)%	0.0%
Electric commercial and industrial	1.7	1.8	1.5	2.4
Total retail electric sales	1.3	1.3	0.5	1.7
Firm natural gas sales	3.0	1.4	4.9	1.9

During 2008, we experienced flat electric residential sales, primarily driven by a decline in the NSP-Minnesota region. We believe the flat sales growth is a reflection of a recent shift in customer behavior, in part, attributable to the overall economic conditions as well as conservation efforts.

Electric — The following ~~tables detail the electric revenues and margin:~~

(Millions of dollars)	Three months ended Dec. 31, 2008	2007	Twelve months ended Dec. 31, 2008	2007
Electric revenues	$ 1,979	$ 1,913	$ 8,683	$ 7,848
Electric fuel and purchased power	(1,077)	(1,024)	(4,948)	(4,137)
Electric margin	$ 902	$ 889	$ 3,735	$ 3,711

The following table summarizes the components of the changes in electric margin for the three-and twelve-months ended Dec. 31, 2008:

(Millions of dollars)	Three months ended Dec. 31, 2008 vs. 2007	Twelve months ended Dec. 31, 2008 vs. 2007
Retail rate increases (Wisconsin, North Dakota, Texas interim and New Mexico)	$ 17	$ 48
Conservation and non-fuel riders	10	28
Sales growth (excluding weather impact)	6	30
Metropolitan Emissions Reduction Project (MERP) rider	6	23
Increased margin due to leap year (weather normalized impact)	—	9
Estimated impact of weather	—	(49)
Purchased capacity costs	(19)	(30)
Retail customer sales mix	1	(8)
Trading margin	(7)	(10)
Revenue subject to refund due to change in nuclear refueling outage recovery method	(2)	(18)
Other, including fuel recovery	1	1
Total increase in electric margin	$ 13	$ 24

Natural Gas — The following table details the changes in natural gas revenues and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin.

(Millions of dollars)	Three months ended Dec. 31, 2008	2007	Twelve months ended Dec. 31, 2008	2007
Natural gas revenues	$ 706	$ 669	$ 2,443	$ 2,112
Cost of natural gas sold and transported	(534)	(498)	(1,833)	(1,548)
Natural gas margin	$ 172	$ 171	$ 610	$ 564

The following table summarizes the components of the changes in natural gas margin for the three-and twelve-months ended Dec. 31, 2008:

(Millions of dollars)	Three months ended Dec. 31, 2008 vs. 2007	Twelve months ended Dec. 31, 2008 vs. 2007
Base rate increase – Colorado and Wisconsin	$ 2	$ 24
Estimated impact of weather	2	10
Sales growth (excluding weather impact)	1	5
Conservation revenues	(1)	3
Increased margin due to leap year (weather normalized impact)	—	1
Other	(3)	3
Total increase in natural gas margin	$ 1	$ 46

Other Operating and Maintenance Expenses — Other operating and maintenance expenses for the fourth quarter of 2008 decreased by $50 million, or 10.2 percent as compared with the same period in 2007. Other operating and maintenance expenses for 2008 decreased by $11 million, or 0.6 percent, compared with 2007. The following table summarizes the components of the changes in other operating and maintenance expenses for the three- and twelve- months ended Dec. 31, 2008:

(Millions of dollars)	Three months ended Dec. 31, 2008 vs. 2007	Twelve months ended Dec. 31, 2008 vs. 2007
Nuclear outage expenses, net of deferral	$ 8	$ (13)
Higher uncollectible receivable costs	7	7
Lower employee benefit costs	(21)	(39)
Higher (lower) plant generation costs	(15)	9
Higher (lower) consulting costs	(7)	7
Higher (lower) material costs	(4)	2
Higher (lower) contract labor	(4)	4
Higher (lower) labor costs	(1)	22
Other, including nuclear plant operation costs	(13)	(10)
Total decrease in other operating and maintenance expenses	$ (50)	$ (11)

The following provides an explanation of the year-to-date change in certain items listed in the table above for 2008 as compared to 2007:

- The decline in nuclear outage expenses is due to the Minnesota Public Utilities Commission (MPUC), North Dakota Public Service Commission (NDPSC) and South Dakota Public Utilities Commission (SDPUC) approving the change in recovery methods for costs associated with refueling outages at our nuclear plants from the direct expense method to the deferral and amortization method, effective Jan. 1, 2008. An accrual was also recorded to lower revenue, reflecting a liability for a customer refund relating to this decision.
- Lower employee benefit costs are due to eliminating our annual performance based incentive plan payout for 2008.
- The higher plant generation costs were primarily attributable to scheduled and unplanned maintenance.
- The increase in labor costs was attributable to annual wage increases, the insourcing of certain functions and additional employees to support system growth.

Depreciation and Amortization — Depreciation and amortization expense increased by approximately $3.7 million, or 1.8 percent, for the fourth quarter of 2008, and increased by $22.6 million, or 2.8 percent for 2008, compared with the same periods in 2007. The increases were primarily due to planned system expansion. These increases were partially offset by a decrease in depreciation due to the MPUC approval of two NSP-Minnesota depreciation filings in September 2008 and a NDPSC settlement agreement in December 2008.

Conservation and Demand Side Management (DSM) — Conservation and DSM expense decreased approximately $0.3 million, or 1.2 percent for the fourth quarter of 2008 and increased $15.9 million, or 15.7 percent, for 2008, compared to the same periods in 2007. The higher expense for 2008 is attributable to the expansion of programs and is designed, in part, to meet regulatory commitments. Conservation and DSM program expenses are generally recovered through riders in Xcel Energy's major jurisdictions or through general rate cases.

Interest and Other Income, net — Interest and other income increased by $7.1 million, for the fourth quarter of 2008, and $33.0 million, for 2008, compared with the same periods in 2007. The increase is primarily due to PSRI's termination of the COLI program in 2007, which eliminated certain expenses.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased by approximately $6.0 million, or 26.6 percent, for the fourth quarter of 2008, and increased by $30.8 million, or 42.8 percent, for 2008 when compared with the same periods in 2007. The increase was due primarily to the construction of Comanche 3, which is nearing its final phase and other construction projects.

Interest charges — Interest charges increased by approximately $17.6 million, or 13.6 percent, for the fourth quarter of 2008, and increased by $32.9 million, or 6.3 percent, for 2008 when compared to the same periods in 2007. The increase was primarily the result of increased debt levels to fund our rate base growth strategy.

Income Taxes — Income taxes for continuing operations increased by $30.7 million for the fourth quarter of 2008, compared with 2007. The effective tax rate for continuing operations was 34.3 percent for the fourth quarter of 2008, compared with 28.8 percent for the same period in 2007. The increase in income tax expense and the higher effective tax rate for fourth quarter 2008 as compared with 2007 was primarily due to an increase in pretax income.

Income taxes for continuing operations increased by $44.2 million for 2008, compared with 2007. The increase in income tax expense was primarily due to an increase in pretax income in 2008. The effective tax rate for continuing operations was 34.4 percent for 2008, compared with 33.8 percent for 2007.

Note 3. Xcel Energy Capital Structure and Financing

Following is the preliminary capital structure of Xcel Energy at Dec. 31, 2008:

(Billions of dollars)	Balance at Dec. 31, 2008	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.6	4%
Short-term debt	0.4	2
Long-term debt	7.7	49
Total debt	8.7	55
Preferred equity	0.1	1
Common equity	7.0	44
Total equity	7.1	45
Total capitalization	$ 15.8	100%

Xcel Energy generally expects to fund its operations and capital investments through internally generated funds and by periodically issuing short-term debt, long-term debt, common stock, preferred stock and hybrid securities.

During the fourth quarter of 2008, Xcel Energy issued the following securities:

- In November 2008, we issued $250 million of 8.75 percent Senior Notes, series due 2018 at Southwestern Public Service Company (SPS)

Current debt financing plans for 2009 include the following:

- Approximately $400 million of first mortgage bonds at Northern States Power Co. (NSP-Minnesota).
- Approximately $400 million of first mortgage bonds at Public Service Company of Colorado (PSCo).

These financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Note 4. Liquidity

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, preferred securities and hybrid securities to maintain desired capitalization ratios.

Short-Term Funding Sources —Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments

General — As a result of recent volatile conditions in global capital markets, general liquidity in short-term credit markets has been periodically constrained. Xcel Energy has maintained access to short-term liquidity through the A2/P2 commercial paper market and utilization of direct borrowing on committed credit agreements. In addition, Xcel Energy's overall liquidity was strengthened by the issuance of long-term debt, equity and hybrid securities completed during 2008. The proceeds from these financings were used to refinance maturing debt obligations, repay short-term debt and general corporate purposes.

Pension Fund – Xcel Energy's pension costs and funding requirements are projected to increase, as a result of the overall distressed global financial conditions and decline in valuations of both the equity and debt markets. Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, fixed income securities, real estate and alternative investments, including private equity funds and a commodities index. With the recent decline in asset value in our pension plans, we expect to have 2009 funding requirements of $70 million to $130 million. At this time, pension funding contributions for 2010, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $250 million. For more information, please refer to the following table:

(Millions of dollars)	Dec. 31, 2008	Dec. 31, 2007
Fair value of pension assets	$ 2,185	$ 3,186
Projected benefit obligation[a]	2,598	2,662
Funded status	$ (413)	$ 524

a – excludes non-qualified plan of $46 million and $42 million at Dec. 31, 2008 and 2007, respectively.

Pension assumptions	2009	2008
Discount rate	6.75 %	6.25 %
Expected long-term rate of return	8.50	8.75

Commercial Paper — Xcel Energy, NSP-Minnesota, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy,
- $500 million for NSP-Minnesota,
- $700 million for PSCo, and
- $250 million for SPS.

Xcel Energy and Utility Subsidiary Credit Facilities — As of Jan. 21, 2009, Xcel Energy had the following credit facilities available to meet its liquidity needs:

(Millions of Dollars)

Company	Facility[1]	Drawn[2]	Available	Cash[3]	Liquidity	Maturity
NSP-Minnesota	$ 482	$ 51	$ 431	$ 2	$ 433	December 2011
PSCo	675	5	670	1	671	December 2011
SPS	248	12	236	229	465	December 2011
Xcel Energy – Holding Company	772	451	321	1	322	December 2011
NSP-Wisconsin[4]	—	—	—	58	58	
Total	$ 2,177	$ 519	$ 1,658	$ 291	$ 1,949	

[1] Reflects a reduction in the commitments resulting from the Lehman Brothers bankruptcy, which reduce the credit facilities by $73 million, collectively.
[2] Includes direct borrowings, outstanding commercial paper and letters of credit.
[3] Reflects the payment of common dividends on Jan. 20, 2009.
[4] NSP-Wisconsin does not have a separate credit facility; however, it has a borrowing agreement with NSP-Minnesota.

Credit Agency Ratings — Short-term and long-term borrowings, as a source of funding, are affected by regulatory actions, capital markets conditions and credit agency ratings. The following ratings reflect the views of Moody's Investor Services, Inc. (Moody's), Standard & Poor's Ratings Services (S&P's), and Fitch Ratings (Fitch). A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. As of Jan. 20, 2009, the following table represents the credit ratings assigned to various Xcel Energy companies:

Company	Credit Type	Moody's	S & P's	Fitch
Xcel Energy	Senior Unsecured Debt	Baa1	BBB	BBB+
Xcel Energy	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A3	BBB+	A
NSP-Minnesota	Senior Secured Debt	A2	A	A+
NSP-Minnesota	Commercial Paper	P-2	A-2	F1
NSP-Wisconsin	Senior Unsecured Debt	A3	A-	A
NSP-Wisconsin	Senior Secured Debt	A2	A	A+
PSCo	Senior Unsecured Debt	Baa1	BBB+	A-
PSCo	Senior Secured Debt	A3	A	A
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa1	BBB+	BBB+
SPS	Commercial Paper	P-2	A-2	F2

On Nov. 5, 2008, S&P increased the senior unsecured credit ratings of NSP-Minnesota, NSP-Wisconsin and PSCo by one notch.

Note 5. Rates and Regulation

Pending Rate Cases

NSP- Minnesota - Minnesota Electric Rate Case — On Nov. 2, 2008, NSP-Minnesota filed a request with the MPUC to increase electric rates in Minnesota by $156 million, or 6.05 percent. The request is based on a 2009 forecast test year, electric rate base of $4.1 billion, a requested return on equity (ROE) of 11.0 percent and an equity ratio of 52.5 percent.

In December 2008, the MPUC approved interim rates of $132 million, or 5.12 percent, effective Jan. 2, 2009. The primary difference between interim rate levels approved and our request of $156 million is due to a previously authorized ROE of 10.54 percent compared to our requested ROE of 11.0 percent.

A decision is expected in October 2009. The following schedule has been established:

- Direct testimony on April 7, 2009;
- Rebuttal on May 5, 2009;
- Surrebuttal May 26, 2009; and
- Evidentiary hearings June 2-9, 2009.

PSCo - Colorado Electric Rate Case — On Nov. 14, 2008, PSCo, filed with Colorado Public Utilities Commission (CPUC) a request to increase Colorado electric rates by approximately $174.7 million, or 7.4 percent. The rate filing is based on a 2009 forecast test year, an electric rate base of approximately $4.15 billion, a requested ROE of 11.0 percent and an equity ratio of 58.08 percent.

A final decision is expected in the summer of 2009. The following schedule has been established:

- Answer Testimony for all intervenors on Feb.13, 2009;
- Rebuttal and Cross-Answer Testimony on March 20, 2009;
- Surrebuttal testimony for all intervenors on April 10, 2009;
- Hearings are scheduled for April 20-May 1, 2009,
- Statement of Position on May 12, 2009.

SPS - Texas Electric Retail Rate Case — On June 12, 2008, SPS filed a rate case with Public Utility Commission of Texas (PUCT), seeking an annual rate increase of approximately $61.3 million, or approximately 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue will decline by $33.1 million, primarily due to fuel savings from the Lea Power Partners LLC (LPP) purchase power agreement.

The rate filing is based on a 2007 test-year adjusted for known and measurable changes, a requested ROE of 11.25 percent, an electric rate base of $989.4 million and an equity ratio of 51.0 percent. The interim rates of $18 million for costs associated with the LPP power purchase agreement went into effect in September 2008. The parties have been in active negotiations since November and SPS is hopeful that they will be able to reach a settlement agreement in the near future.

SPS – New Mexico Retail Electric Rate Case — On Dec. 18, 2008, SPS filed with the New Mexico commission a request to increase electric rates in New Mexico by approximately $24.6 million, or 5.1 percent. The request is based on a historic test year (split year based on year-ending June 30, 2008), an electric rate base of $321 million, an equity ratio of 50 percent and a requested ROE of 12 percent. SPS also requested interim rates to allow it to begin recovering the cost of the Lea Power facility of approximately $7.6 million. The New Mexico Public Regulation Commission (NMPRC) has set the interim rate request for hearing for March 19, 2009.

On January 12, 2009, the Staff and the Attorney General (AG) requested that the NMPRC suspend SPS' advice notice and deny our request for interim relief. The staff stated that the standard for interim relief requires clear and convincing evidence of a financial emergency, which SPS has failed to provide. The AG stated that our testimony does not rise to the level required for the NMPRC to grant interim relief.

SPS 2008 Wholesale Rate Case — On March 31, 2008, SPS filed a wholesale electric rate case. SPS is seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. Four New Mexico Cooperatives filed a motion for dismissal and protest in April 2008.

On May 30, 2008, the Federal Energy Regulatory Commission (FERC) conditionally accepted and suspended the rates and established hearing and settlement procedures. The FERC granted a one-day suspension of rates instead of 180 days. The LPP plant achieved commercial operations in September 2008 and the proposed base rates, based on a 10.25 percent ROE and a 12-coincident peak demand allocator, became effective, subject to refund. A pre-hearing conference has been set for Jan. 29, 2009. A decision is pending.

Completed Rate Cases

NSP-Minnesota - North Dakota Electric Rate Case — On Dec. 7, 2007, NSP-Minnesota filed with the NDPSC, a request to increase electric rates by $20.5 million, which would be an $18.2 million impact to NSP-Minnesota due to the transfer of certain costs and revenues between base rates and the fuel cost recovery mechanism. The request is based on a common equity ratio of 51.77 percent, a ROE of 11.5 percent and a rate base of approximately $242 million. Interim rates of $17.2 million were effective on Feb. 5, 2008.

The NDPSC approved a settlement agreement on Dec. 31, 2008, which calls for a base rate increase of $12.8 million, based on an authorized ROE of 10.75 percent. Key terms of the settlement are listed below:

- Adjustments in depreciation expenses related to service life changes for generation plants and removal rates for transmission and distribution plant, resulting in a $2.5 million decrease in the revenue deficiency.
- Sharing of wholesale margins, refunding to customers 85 percent of asset-based wholesale margins and 50 percent of non-asset-based margins through the fuel clause. Test year wholesale margins to be shared with customers are estimated to be $1.9 million.
- An electric rate moratorium, under which NSP-Minnesota agreed to not implement an increase in electric rates until Jan. 1, 2011.
- Sharing of any earnings in excess of the authorized 10.75 percent ROE, providing customers 50 percent of any earnings above 10.75 percent and 75 percent of any earnings above 11.25 percent.
- The MPUC terminated the 2005 proceeding regarding recovery of MISO Day 2 market charges and approved fuel clause adjustment (FCA) recovery of all Day 2 charges through the FCA retroactively and prospectively.

Based on the final order, there is an estimated refund of interim rates of $6.3 million, expected to be completed by June 1, 2009. This refund was accrued for in 2008 and will have no impact on 2009 results. Final rates will be implemented for service on and after March 1, 2009.

NSP-Wisconsin - Electric Limited Reopener 2009 Rate Case — On Aug. 1, 2008, NSP-Wisconsin filed with the Public Service Commission of Wisconsin (PSCW) a request to increase retail electric rates by $47.1 million. In the application, NSP-Wisconsin requested the PSCW to reopen the 2008 base rate case for the limited purpose of adjusting 2009 electric rates to reflect forecasted increases in production and transmission costs, as authorized by the PSCW. No changes were requested to the capital structure or ROE authorized by the PSCW in the 2008 base rate case.

On Dec. 30, 2008, the PSCW issued an order approving the stipulation agreement, entered into between NSP-Wisconsin and various intervenors, authorizing a $5.6 million rate increase. The original request of $47.1 million was reduced by $31.6 million due to the dramatic decline in market prices for fuel and purchased power, $5.5 million for a change in nuclear outage accounting and $4.4 million due to other adjustments.

Further, in accordance with the stipulation agreement, an estimated 2008 interim fuel surcharge refund liability of $9.8 million, previously recorded in 2008, will be offset by the $5.6 million 2009 rate increase, and the remaining liability will be refunded to customers in the first quarter of 2009, after the PSCW completes its final review of 2008 actual fuel costs.

Note 6. Xcel Energy Earnings Guidance

Xcel Energy's 2009 earnings guidance is $1.45 to $1.55 per share. Key assumptions are detailed below:

- Normal weather patterns are experienced for the year.
- Reasonable regulatory outcomes in the Minnesota electric rate case, the Colorado electric rate case, the Texas electric rate case, the New Mexico electric rate case, the SPS FERC wholesale electric rate cases and other rate cases that may be filed during the year.
- Various riders, associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, are expected to increase revenue by approximately $50 million to $60 million over 2008 levels.
- Weather adjusted electric retail sales growth of 0.0 percent to 0.5 percent.
- Weather adjusted retail firm natural gas sales decline by approximately (1.0) percent to 0.0 percent.
- Capacity costs are projected to increase approximately $45 million over 2008 levels. Capacity costs at PSCo are recovered under the purchased capacity cost adjustment.
- Operating and maintenance expenses are projected to increase:
  - Nuclear (including outage amortization) $55 million
  - Pension and medical $25 million
  - Other (including incentive compensation) $75 million - $125 million
- Depreciation and amortization expense is projected to increase approximately $80 million to $90 million over 2008.
- Interest expense increases approximately $20 million to $30 million over 2008 levels.
- Allowance for funds used during construction-equity decreases approximately $5 million to $10 million over 2008.
- An effective tax rate for continuing operations of approximately 33 percent to 35 percent.
- Average common stock and equivalents of approximately 457 million shares.

Note 7. Non-GAAP Reconciliation

The following table provides a reconciliation of GAAP earnings to ongoing earnings:

	Three months ended Dec. 31,		Twelve months ended Dec. 31,	
(Thousand of dollars)	2008	2007	2008	2007
Ongoing earnings	$ 158,586	$ 131,504	$ 641,122	$ 612,013
PSRI/COLI IRS settlement	4,971	3,465	4,598	(36,114)
Total continuing operations	163,557	134,969	645,720	575,899
Income (loss) from discontinued operations	518	(927)	(166)	1,449
GAAP earnings	$ 164,075	$ 134,042	$ 645,554	$ 577,348

As a result of the termination of the COLI program, Xcel Energy's management believes that ongoing earnings provide a more meaningful comparison of earnings results between different periods in which the COLI program was in place and is more representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the board of directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

XCEL ENERGY INC. AND SUBSIDIARIES
UNAUDITED EARNINGS RELEASE SUMMARY
All amounts in thousands, except earnings per share

Three months ended Dec. 31,	2008	2007
Operating revenues:		
Electric and natural gas and trading revenues	$ 2,685,116	$ 2,582,242
Other	22,457	20,977
Total operating revenues	2,707,573	2,603,219
Income from continuing operations	163,557	134,969
Income (loss) from discontinued operations	518	(927)
Net income	164,075	134,042
Earnings available to common shareholders	163,015	132,982
Weighted average diluted common shares outstanding	455,174	434,009
Segments and Components of Earnings per Share — Diluted		
Regulated utility segments — continuing operations	$ 0.38	$ 0.33
Holding company and other costs	(0.03)	(0.03)
Earnings per share - ongoing operations	0.35	0.30
PSRI/COLI IRS settlement	0.01	0.01
Total earnings per share	**$ 0.36**	**$ 0.31**

Twelve months ended Dec. 31,	2008	2007
Operating revenues:		
Electric and natural gas and trading revenues	$ 11,125,981	$ 9,959,724
Other	77,175	74,446
Total operating revenues	11,203,156	10,034,170
Income from continuing operations	645,720	575,899
Income (loss) from discontinued operations	(166)	1,449
Net income	645,554	577,348
Earnings available to common shareholders	641,313	573,107
Weighted average diluted common shares outstanding	441,813	433,131
Segments and Components of Earnings per Share — Diluted		
Regulated utility segments — continuing operations	$ 1.59	$ 1.55
Holding company and other costs	(0.14)	(0.12)
Earnings per share - ongoing operations	1.45	1.43
PSRI/COLI IRS settlement	0.01	(0.08)
Total earnings per share	**$ 1.46**	**$ 1.35**
Book value per share	$ 15.35	$ 14.70

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Xcel Energy Inc · 10-K · For 12/31/08

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Document/Exhibit		Description	Pages	Size
1:	**10-K**	**Annual Report**	**HTML**	**1,792K**
2:	EX-10.02	Material Contract	HTML	196K
3:	EX-10.05	Material Contract	HTML	130K
4:	EX-10.06	Material Contract	HTML	45K
5:	EX-10.07	Material Contract	HTML	242K
6:	EX-10.08	Material Contract	HTML	22K
7:	EX-10.17	Material Contract	HTML	96K
8:	EX-10.21	Material Contract	HTML	13K
9:	EX-10.22	Material Contract	HTML	12K
10:	EX-12.01	Statement re: Computation of Ratios	HTML	32K
11:	EX-21.01	Subsidiaries of the Registrant	HTML	20K
12:	EX-23.01	Consent of Experts or Counsel	HTML	13K
13:	EX-24.01	Power of Attorney	HTML	26K
14:	EX-31.01	Certification per Sarbanes-Oxley Act (Section 302)	HTML	14K
15:	EX-31.02	Certification per Sarbanes-Oxley Act (Section 302)	HTML	14K
16:	EX-32.01	Certification per Sarbanes-Oxley Act (Section 906)	HTML	11K
17:	EX-99.01	Miscellaneous Exhibit	HTML	13K

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NoCapX & UCAN
Exhibit J

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Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2009, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2006	2007	2008	2009 Forecast
NSP System	9,859	9,427	8,697	9,662

The peak demand for the NSP System typically occurs in the summer. The 2008 system peak demand for the NSP System occurred on July 29, 2008.

Energy Sources and Related Transmission Initiatives

NSP-Minnesota expects to use existing power plants, power purchases, DSM options, new generation facilities and expansion of existing power plants to meet its system capacity requirements.

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Capacity is the measure of the rate at which a particular generating source produces electricity. Energy is a measure of the amount of electricity produced from a particular generating source over a period of time. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

NSP-Minnesota also makes short-term purchases to comply with minimum availability requirements, to obtain energy at a lower cost and for various other operating requirements.

Purchased Transmission Services — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

Excelsior Energy — In December 2005, Excelsior, an independent energy developer, filed a power purchase agreement with the MPUC seeking a declaration that NSP-Minnesota be compelled to enter into an agreement to purchase the output from two integrated gas combined cycle (IGCC) plants to be located in northern Minnesota as part of the Mesaba Energy Project. Excelsior filed this petition making claims pursuant to Minnesota statutes relating to an Innovative Energy Project and Clean Energy Technology. NSP-Minnesota opposed the petition.

The MPUC referred this matter to a contested case hearing before an ALJ to act on Excelsior's petition. The contested case proceeding considered a 600 MW unit in Phase 1 and a second 600 MW unit in Phase 2 of the Mesaba Energy Project.

The MPUC issued its order for phase 1 of the hearing on Aug. 30, 2007. In it, the MPUC found among other things, that Excelsior and NSP-Minnesota should resume negotiations toward an acceptable purchase power agreement, with assistance from the Minnesota Department of Commerce (MDOC) and the guidance provided by the order.

On Sept. 24, 2008, the MPUC denied Excelsior Energy's Phase 2 request to approve a power purchase agreement related to its proposed second 600 MW IGCC facility. The MPUC also set a May 1, 2009 deadline for Phase 1 of the proceeding in which it had previously ordered negotiations. On Oct. 14, 2008, Excelsior sought rehearing of the MPUC's Sept. 24, 2008 order. On Dec. 9, 2008, the MPUC held further action in abeyance until after the May 1, 2009 deadline.

GHG Emissions — The 2007 Minnesota legislature adopted the goal to reduce statewide GHG emissions across all sectors to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.

The legislation also prohibits the construction within Minnesota of a new large energy facility, the import or commitment to import from outside Minnesota power from a new large energy facility, or entering into a new long-term power purchase agreement that would increase statewide power sector CO_2 emissions. The statute does not impose limitations on CO_2 or other GHG emissions on NSP-Minnesota and provides for certain exemptions. On Feb. 1, 2008, the MDOC submitted to the legislature a climate change action

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 5
77 WEST JACKSON BOULEVARD
CHICAGO, IL 60604-3590

JAN 11 2008

REPLY TO THE ATTENTION OF:

E-13J

Richard A. Hargis
National Energy and Technology Laboratory
P.O. Box 10940
Pittsburgh, PA 15236-0940

RE: Draft Environmental Impact Statement, Mesaba Energy Project, CEQ # 20070471

Dear Mr. Hargis:

The U.S. Environmental Protection Agency (EPA) has reviewed the Draft Environmental Impact Statement (DEIS) for the Mesaba Energy Project. We offer our comments under the National Environmental Policy Act (NEPA), and Section 309 of the Clean Air Act.

The Mesaba Energy Project is a two-phase 1,212-megawatt facility that has a project operating period of 20 years, provided the 1-year trial is successful. Phase I, proposed to be co-funded by DOE, is a 606-MW plant; Phase II is an identical, co-located and privately funded 606-MW plant. The project is proposed by Excelsior Energy under DOE's Clean Coal Power Initiative (CCPI) competitive solicitation. DOE selected the project to demonstrate commercial viability of the integrated gasification combined cycle (IGCC) process.

The preferred alternative is a 1,200-acre site near Taconite, MN (Itasca County); the alternative evaluated is an 810-acre site near Hoyt Lakes, MN (St. Louis County). Connected actions included road construction, road modifications, and right-of-way considerations for railroad spurs, power lines, and gas pipelines. Both locations are near Federal Class I air quality areas (Boundary Waters Canoe Area and Voyageurs National Park). The alternatives would have direct impacts to between 133 and 172 acres of wetlands.

Based on the information provided in the DEIS, EPA has assigned a rating of "EO-2." The "EO" indicates that we have environmental objections to the proposed project. The "2" indicates that additional information needs to be provided to support the impact analysis documented in the DEIS. This rating will be published in the Federal Register. Our objections are based on the alternatives analysis and direct impacts to wetlands, and we question whether the project will meet Clean Water Act Section 404 requirements for selecting the least environmentally damaging preferred alternative (LEDPA). Discussion of this issue and comments on other topic are enclosed.

NoCapX & UCAN
Exhibit K

Thank you for the opportunity to review and provide comments on the DEIS. We look forward to working with you and the cooperating federal agencies on resolving our comments. If you have any questions or would like to discuss our concerns and recommendations, please contact Anna Miller of my staff at either miller.anna@epa.gov or (312) 886-7060.

Sincerely yours,

Alan Walts
Acting Director, Office of Enforcement and Compliance Assurance

Enclosures

EPA Region 5 Comments for the
Mesaba Energy Project
Draft Environmental Impact Statement (DEIS)
January 10, 2008

Project Purpose and Alternatives Analysis
EPA questions whether the project meets Clean Water Act (CWA) Section 404 requirements for selecting the least environmentally damaging preferred alternative (LEDPA). The Clean Water Act (CWA) Section 404(b)(1) Guidelines for Specification of Disposal Sites for Dredged or Fill Material, at 40 CFR Part 230 (Guidelines) require that a sequence of planning steps be demonstrated that involves avoidance, minimization, and compensation for stream and wetland loss associated with unavoidable impacts to waters of the U.S. The avoidance requirements are found in 40 CFR 230.10(a), which state: "Except as provided under Section 404(b)(2), no discharge of dredged or fill material shall be permitted if there is a practicable alternative to the proposed discharge which would have less adverse impact on the aquatic ecosystem, so long as the alternative does not have other significant adverse environmental consequences." The selection of alternatives is determined in part by the project's purpose. EPA has questioned other CWA Section 404 permit applications (during the Army Corps of Engineers public notice process) where the purpose was too broad or too specific and excluded viable alternatives.

This project has four stated purposes, which are to: 1) demonstrate the commercial viability of IGCC technology on a utility-scale application, 2) help satisfy Minnesota's baseload power needs, 3) implement Minnesota's energy policies, 4) and utilize state and federal incentives under the Innovative Energy Project initiative. These four stated purposes are actually a combination of two project purposes and a set of modifiers that specify the applicant's desired conditions and benefits for the project. The demonstration of the commercial viability of IGCC technology on a utility-scale application (1) is one project purpose that can be accomplished anywhere in the United States, not just in Minnesota. The need to provide additional baseload power in Minnesota (2) is another project purpose, which can be accomplished using a number of different technologies, fuels, and locations within the State. It does not require the use of IGCC technology. The purpose to implement Minnesota's energy policies (3) is actually a desired benefit from the second project purpose. This benefit cannot be considered as a project purpose because it isn't associated with an actual project. Lastly, the purpose to utilize state and federal incentives (4) is a desired condition by the applicant that cannot be considered a project purpose. The economic savings and development benefits associated with these incentives do not define an actual project either.

The four stated purposes are very specific and conditional; as a result, they narrowly define the project such that all practicable alternatives except those in a portion of Minnesota known as the Taconite Tax Relief Area (TTRA) are excluded. Therefore, we would, in reviewing the CWA Section 404 permit, reject the project purposes as stated by the applicant and the resulting alternatives analysis upon which it is based. In general, EPA recommends that CWA Section 404 applicants satisfy the LEDPA requirement by evaluating alternatives related to a single project purpose, or a set of related purposes that do not eliminate viable alternatives in favor of desirable project benefits which are separate from the project's purpose. From our understanding of DOE's goals, the basic project purpose is (1): To demonstrate the commercial viability of IGCC technology. This purpose would not restrict the alternatives analysis to the TTRA and would allow the pursuit of the least environmentally damaging, most practicable alternative available.

> Recommendations:
> We recommend that the Final EIS (FEIS) identify one project purpose: demonstrating the commercial viability of IGCC technology is the prime purpose for the project, as selected and presented by the DOE for funding under the CCPI. We also recommend that the alternatives analysis be based on this project purpose.
>
> We recommend that the DOE/applicant explain why the economic benefits of only considering alternative locations in the TTRA are critical to the project, given the cost of wetlands mitigation and other costs tied to the present alternatives analyzed in the DEIS.

Based on our review of the DEIS, other alternatives within the TTRA were dismissed for unclear reasons that are not supported by data, maps, and other specific information presented in a format that compares alternatives directly to one another. A more quantitative discussion is needed for some of the eliminated alternatives. For example, in Appendix F1, the Hibbing Industrial Park site is designated "unavailable" without a specific reason.

> Recommendation: We recommend that the DOE/applicant include quantitative information and data on siting variables, including cost, wetlands acreage and impacted wetlands types, to compare alternatives.

Wetland Mitigation
EPA recommends that the FEIS quantify mitigation for wetlands losses, identify potential locations and replacement ratios, and describe the project's mitigation plan and timeframe for both permanent and temporary impacts. EPA is concerned with the wetlands mitigation for this project for several reasons:

1) Wetlands already comprise a relatively high percentage of total land cover in the project area, meaning that few areas are available for mitigation;
2) Existing opportunities available for creating wetlands (reclaiming old mine pits and tailings basins) represent far less than ideal mitigation, especially for the variety and types of wetlands being impacted (which include forested wetlands and bogs); and
3) The demand for wetland mitigation in the watershed is high, due to other projects under development (e.g. mining projects) that will also incur significant wetland impacts.

Therefore, mitigation will require thorough planning. In addition, the loss of forested and bog wetland habitat typically require higher than 1:1 mitigation ratios because of the extended period of time (decades) that their functions will be lost while mitigation areas are establishing themselves.

> Recommendation: We recommend that the FEIS include specific information on how the applicant intends to provide mitigation for the wetland impacts incurred by this project, including information on potential mitigation sites, commitments to replace lost wetlands with a comparable type, expected mitigation ratios, and long-term mitigation monitoring.

Permanent and Temporary Wetland Impacts

The West Range Site has estimated permanent impacts of 172 acres of wetlands; the East Range Site has estimated permanent impacts of 133 acres. The DEIS is unclear on what amount of temporary impact will occur to shrub, forested, and bog wetlands through the placement of utility lines and the construction of transportation corridors. The impacts to shrub, forested, and bog wetlands would not be temporary because only emergent vegetation would be allowed to return to these maintained rights of way.

> Recommendation: We suggest the FEIS reevaluate wetlands impacts from utility lines and transportation corridors as more than temporary impacts and provide mitigation of these impacts under the mitigation plan.

Wetlands Classification

The use of the Circular 39 classification system to describe the wetlands impacted is problematic because it does not provide sufficient information on the wetland types being impacted. For example, Circular 39 Type 7 (wooded swamp) does not distinguish between hardwood swamps and coniferous swamps, which are two very different types of plant communities. Similarly, Circular 39 Type 2 does not differentiate between sedge meadow and calcareous fen; these are distinctly different wetland community types and each would be assessed differently regarding what constitutes adequate mitigation.

> Recommendation: EPA recommends that the FEIS use the Eggers and Reed system (1997) or the Cowardin Classification. Both Eggers and Reed and Cowardin provide more specific plant community information that will be useful and necessary to determine adequate mitigation. We recommend their use to identify wetland impacts as well as to describe the wetland communities to be established for mitigation.

Air Emissions

EPA is aware that the Minnesota Pollution Control Agency (MPCA) and the project applicant are discussing air emissions and air permitting requirements. EPA will continue to discuss air permitting factors with MPCA, which has authority for direct implementation of the Clean Air Act in Minnesota.

We appreciate that the DEIS includes projected annual emissions for CO_2 and discusses the general effects of greenhouse gas emissions and global climate change. We also note that the DEIS has described how the facility will be designed for possible retrofitting of

CO_2 capture technology. This information is useful to the general public in understanding the project.

Recreational Use of Canesteo Mine Pit
The applicant has requested that Canesteo Mine Pit be closed for recreational uses to meet security requirements for process water intake facilities, should the West Range alternative (the DEIS's preferred alternative) be selected; therefore the loss of this resource is a potential outcome of this project.

> Recommendation: EPA recommends that the DEIS discuss whether the Minnesota Department of Natural Resources' decision on the applicant's request to close recreational use of the pit would affect site selection or possibly result in changes to the water management plan described in the DEIS. The DEIS should also identify that a feature of the West Range proposal is the elimination of the pit's recreational use, when the Canesteo Mine Pit is discussed in other sections (such as in the project description and in the water management plan). This information will be useful for public reviewers to understand the project's impacts.

Water Quality
EPA is aware that the MPCA and the project applicant are discussing water management and water quality, pursuant to the National Pollutant Discharge Elimination System (NPDES) permit program under the Clean Water Act. EPA will discuss water quality and discharge permitting factors with MPCA, which has authority for direct implementation of the NPDES program in Minnesota, as necessary.