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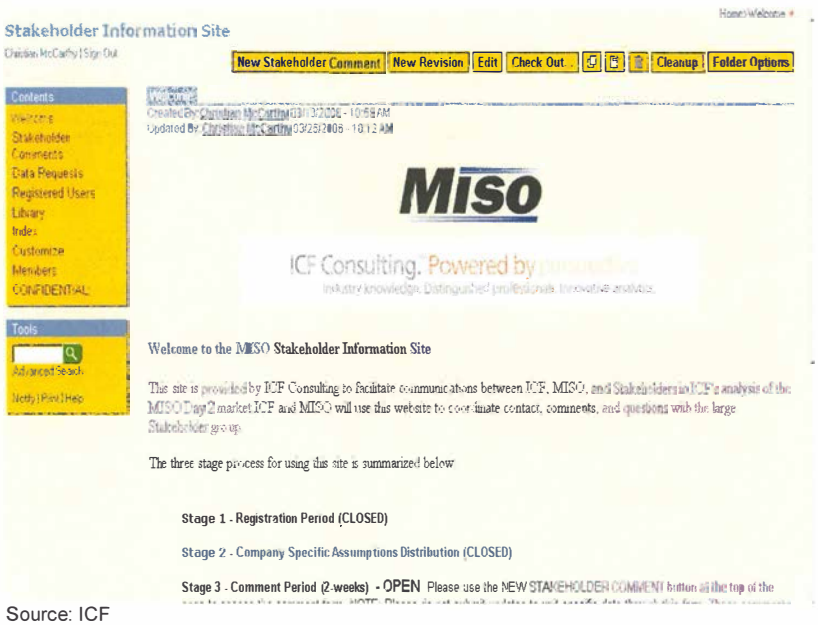
independent power producers active in the Midwest ISO market. The following outline details the steps taken by ICF to ensure Stakeholder participation:

- **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

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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.

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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

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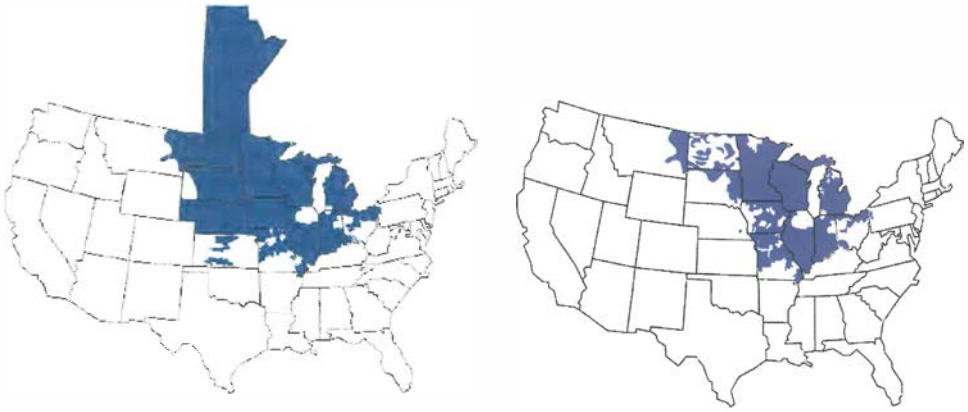
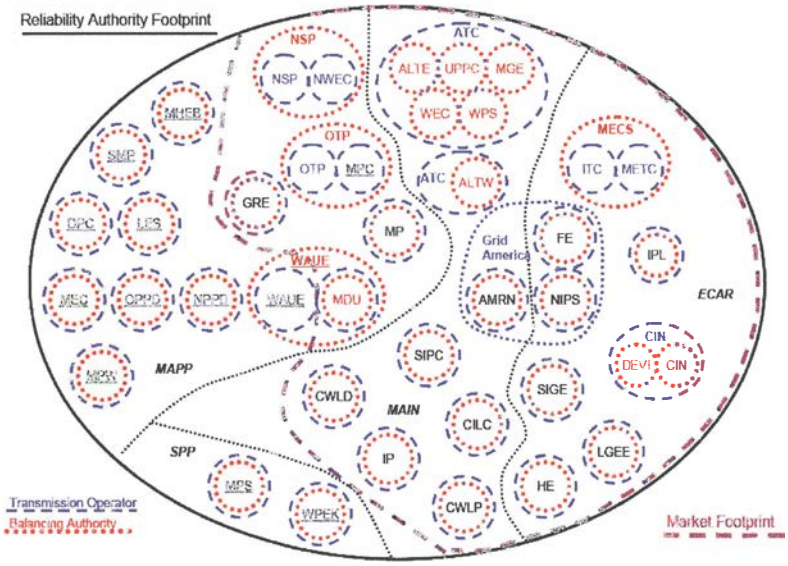
Exhibit 3-2:
The Midwest ISO Reliability and Market Footprints

Reliability Footprint **Market Footprint**



Source: Midwest ISO

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



Note 1: Systems under Midwest ISO Reliability Authority but not under the Energy Markets are shown as underlined.

Note 2: MDU is a pseudo Balancing Authority under Midwest ISO.

Note 3: ITC and METC are treated as separate Balancing Authorities for the Energy Markets.

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

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Supply-Side Assumptions

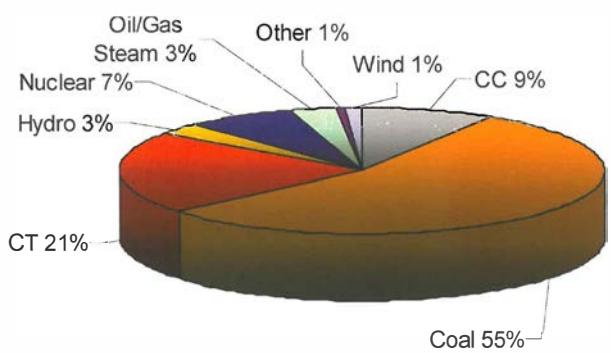
This section focuses on the key supply-side assumptions underlying the analysis. These include the following 5 broad categories:

- 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.

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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

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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.

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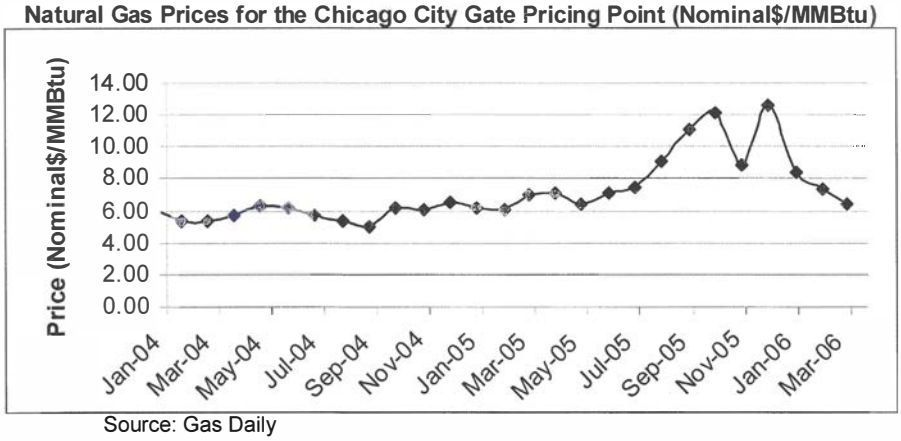
Exhibit 3-6:
Natural Gas Prices for the Chicago City Gate Pricing Point (Nominal$/MMBtu)



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.

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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.

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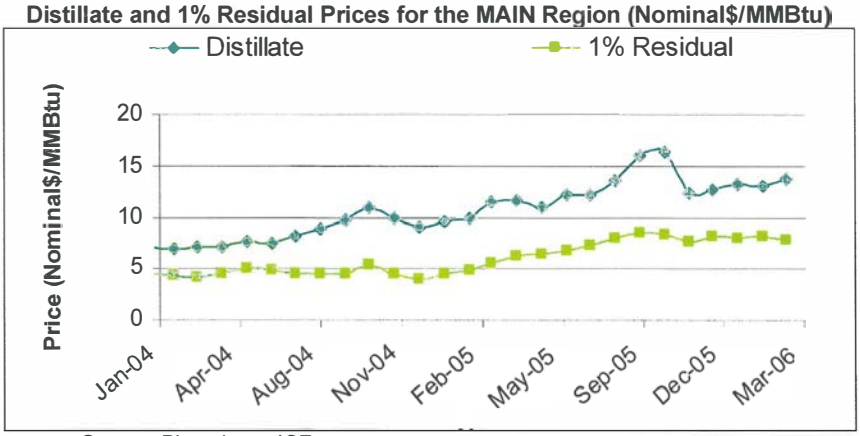
Oil Prices

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

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

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

Source: Bloomberg, ICF

Coal Prices

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

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

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

ICF originally intended to use spot price as the best estimate of the replacement cost of coal prices during the study period. Unfortunately, due to the long-term contracts that dominate the coal industry, less than 40 percent of the reported prices were spot prices. While it may have been feasible to extrapolate the spot prices to cover all data points, available spot prices tend to cluster around a handful of coal plants. For most of the ten months, spot price data were available for less than 50 unique plants out of the more than 140 coal facilities in the Midwest ISO footprint. Because coverage was low, there was insufficient data to extrapolate a contract/spot relationship. Therefore, ICF used the total delivered price which is a weighted average of both spot and contract prices for each facility. The decision to utilize a weighted average coal price for every hour of the month means that in some hours the actual coal price was greater than simulated whereas in other hours the actual coal price was less than simulated. The larger the gap between actual and simulated coal price the greater the error in the simulation result for that hour relative to what actually occurred. Assuming more or less equal distribution of “over” and “under” hours, the average effect should not greatly impact the analytic results.

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

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

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

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

Environmental Compliance Costs

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

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

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

Source: *Air Daily*

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

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

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Exhibit 3-12:
Must Run Assumptions

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

Source: Stakeholders; Midwest ISO

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Demand-Side Assumptions

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

Exhibit 3-13:
Midwest ISO Membership

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

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

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

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

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

Source: Midwest ISO

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Operating Reserves

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

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

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

Source: Midwest ISO

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

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

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

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

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

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

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

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

Source: Midwest ISO

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

Canadian Imports and Exports

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

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

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

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

Transmission Assumptions

Network Model

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

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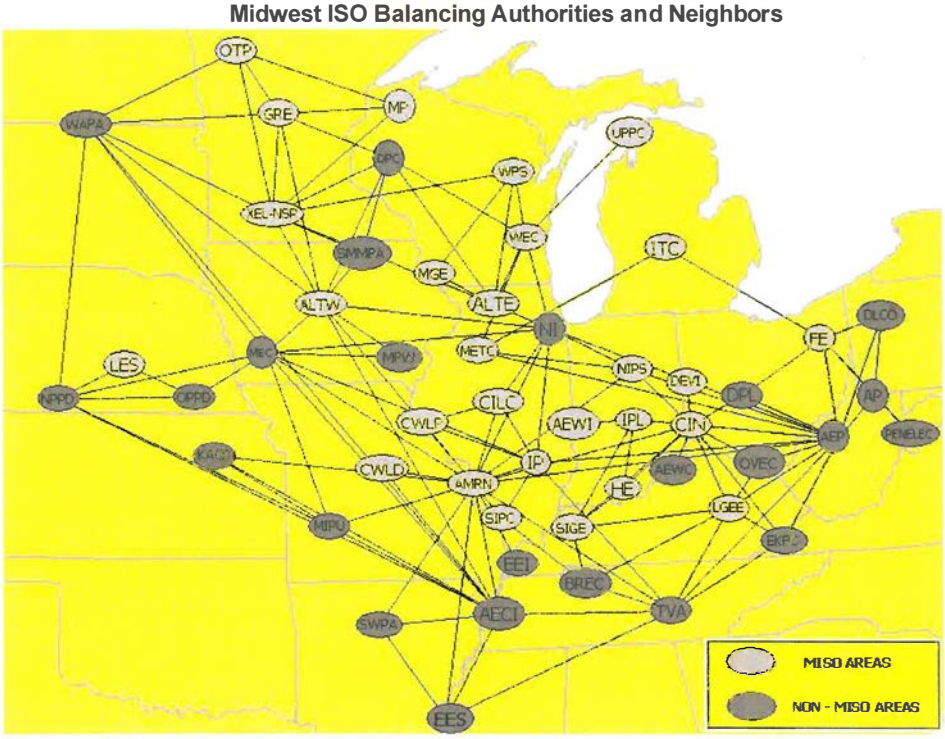
normal, long-term, and short-term emergency limits based on data provided in Midwest ISO's network model. Exhibit 3-18 shows Balancing Authority interconnections for Midwest ISO and neighboring zones as specified in the Midwest ISO network model.

Exhibit 3-18:
Midwest ISO Balancing Authorities and Neighbors



Transmission Facility- Additions and Upgrades

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

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Exhibit 3-19:
Major Transmission Facility Additions and Upgrades

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

Source: Midwest ISO

Flowgates

ICF has explicitly modeled all designated NERC and Midwest ISO flowgates[49] in this analysis. Flowgates are usually the sensitive and often stressed locations in the grid and the most frequent requiring generation redispatch to keep flows within limits. Transmission flowgates are frequently monitored for potential line overloads should there be contingency and/or emergency conditions such as outage of line(s) or generation plant(s) or both. There are approximately 1,000 NERC flowgates, 100 Midwest ISO flowgates and 10 rule-based limits (nomograms) that were modeled with explicit monthly limits for this analysis.

Although flowgate limits vary on an hourly basis, it is not practical to include hourly flowgate limits in the simulation model. ICF and Midwest ISO decided to model monthly limits. For Day-1 modeling, every flowgate limit was reduced by a certain percentage (Exhibit 3-20) based on actual flowgate utilization during level-3 and higher TLR events. This assumption is based on analysis performed by the Midwest ISO and documented in a memorandum distributed to the study stakeholder group.

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

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

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

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CHAPTER FOUR:
DETAILED STUDY RESULTS AND CONCLUSIONS

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

Calibration Case Results

Calibrated Hurdle Rates

The determination of the appropriate level of hurdle rates is achieved through a detailed modeling exercise in which hurdle rates are introduced in the model to calibrate the simulated model outcome to historical market outcomes. The commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provides information to guide fine tuning of the commitment or dispatch hurdles, or both. Specifically, for each unit within the Midwest ISO, the model determines hourly whether the unit should be committed and dispatched. This is done through a multi-pass commitment process that performs hourly commitment of resources to serve load while simultaneously looking one week ahead[50]. Thus the total number of hours the unit is committed and dispatched (and associated generation) can be imputed for the year. Note that in the model, a unit that is not committed will not dispatch; consequently, the level of commitment (in hours) will always be greater than or equal to the level of dispatch. Through the iterative calibration process, the model's projections for unit commitment and dispatch were compared to actual historical operation, especially for units that showed large deviations, to determine the appropriate hurdle rate adjustments. For example, if a unit that historically dispatched in 2004 did not dispatch as much in the 2004 calibration model and also did not commit as much as would be required to permit the level of historical dispatch, then the commitment hurdles affecting that unit were adjusted. In contrast, if the unit was committed as expected, but did not dispatch as much as it actually did historically, then the appropriate dispatch hurdles were adjusted.

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

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

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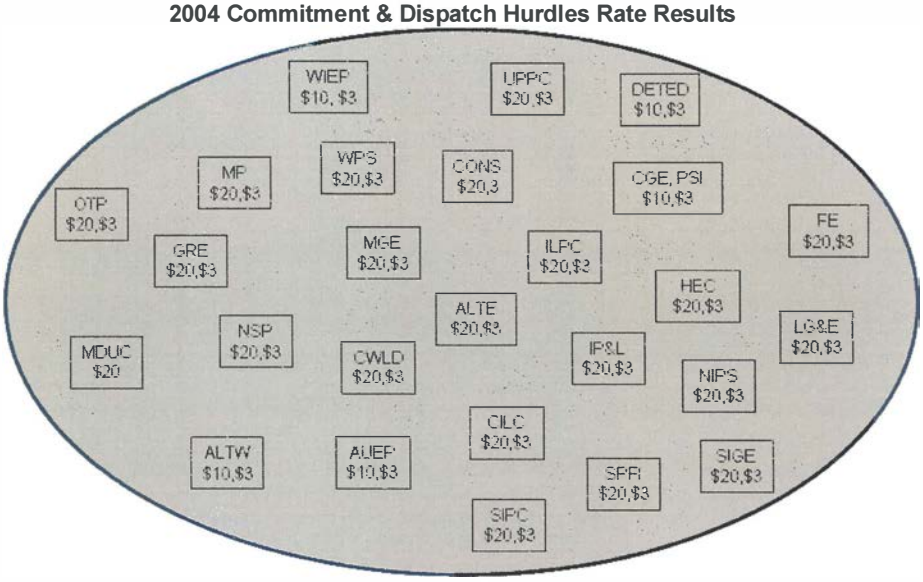
Exhibit 4-1:
2004 Commitment & Dispatch Hurdles Rate Results



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

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

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

Calibration Statistics

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

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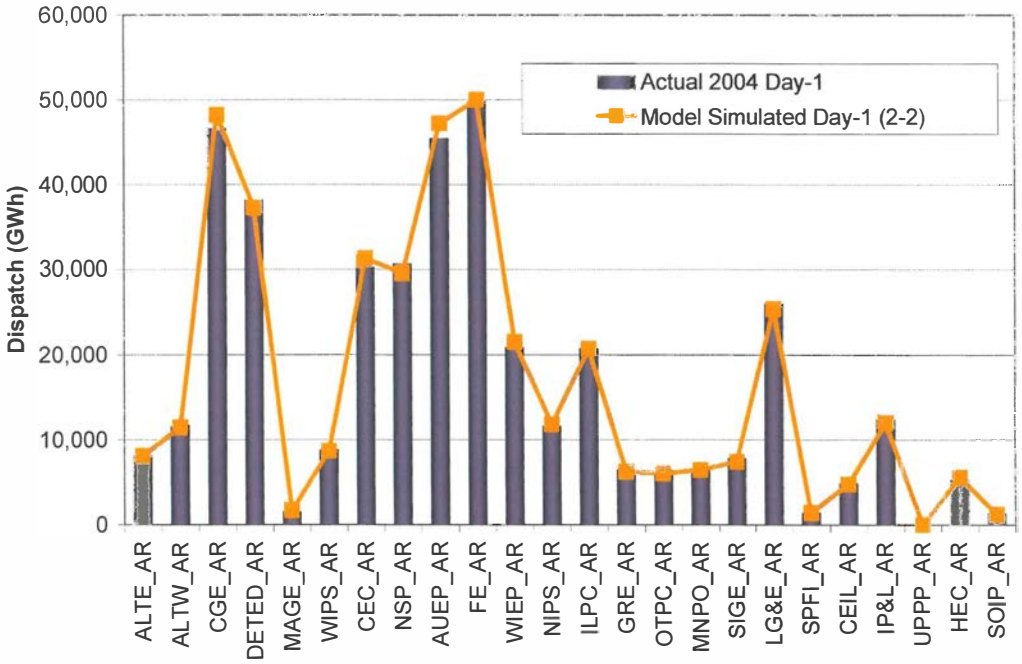
Exhibit 4-2:
Summary Calibration Statistics

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

Source: ICF

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



Source: ICF

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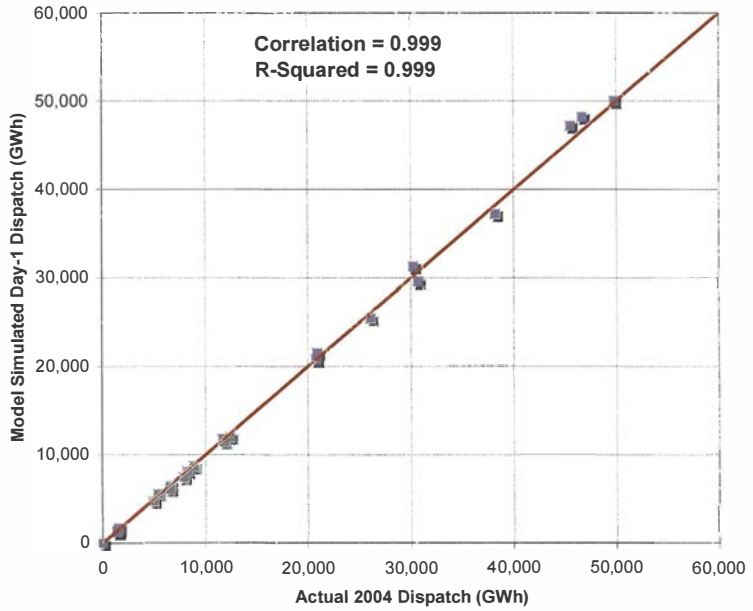
Exhibit 4-4:
Total Dispatch by Balancing Authority– 2004 Actual vs. ICF Calibration



Source: ICF

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

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

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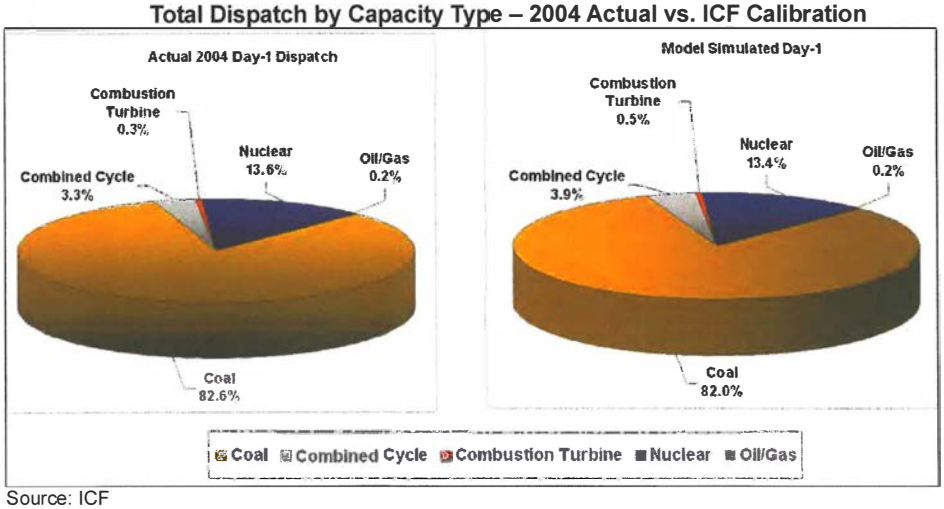
Balancing Authority	Abbreviation	2004 Actual Dispatch	Calibration Results
Great River Energy	GRE	6,535	6,273
Otter Tail Power	OTPC	6,513	6,068
Minnesota Power	MNPO	6,566	6,481
Sothern Indiana Gas & Electric	SIGE	7,874	7,456
Louisville Gas & Electric	LG&E	26,095	25,440
Springfield Water & Power	SPFI	1,464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

Source: ICF

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



Source: ICF

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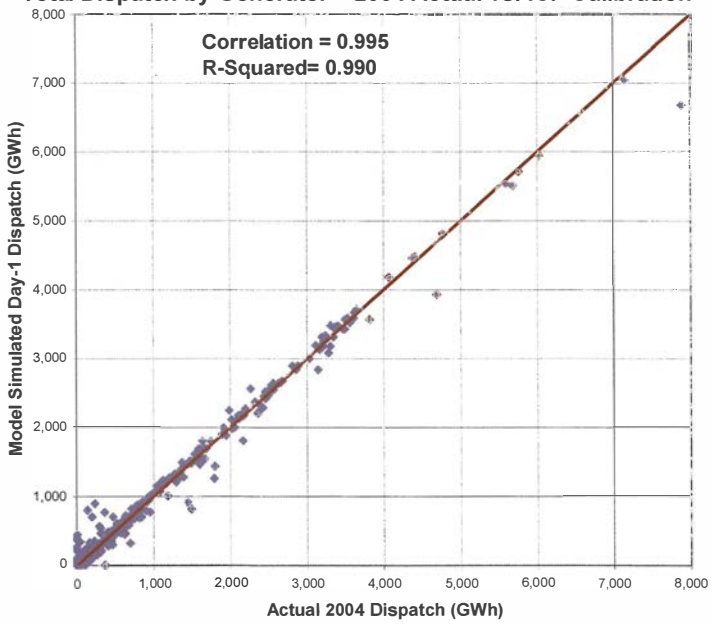
Exhibit 4-7:
Total Dispatch by Generator – 2004 Actual vs. ICF Calibration



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.

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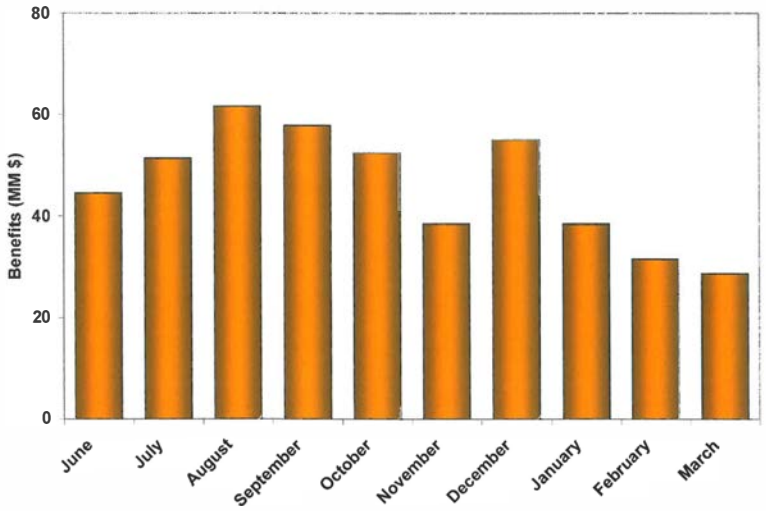
Exhibit 4-8:
Summary of Maximum Potential Benefits - June 2005 through March 2006



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

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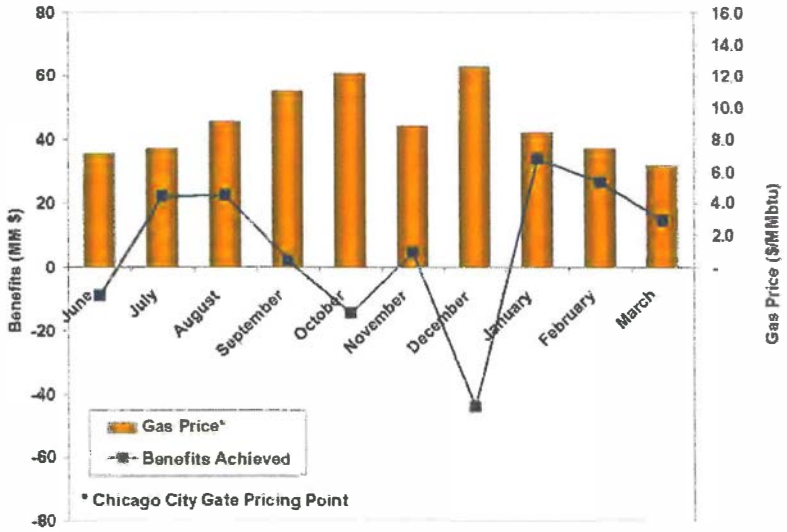
level of potential benefits is comparable to other studies of the potential benefits of centralized dispatch.[51]

- 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.

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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.

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- **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.

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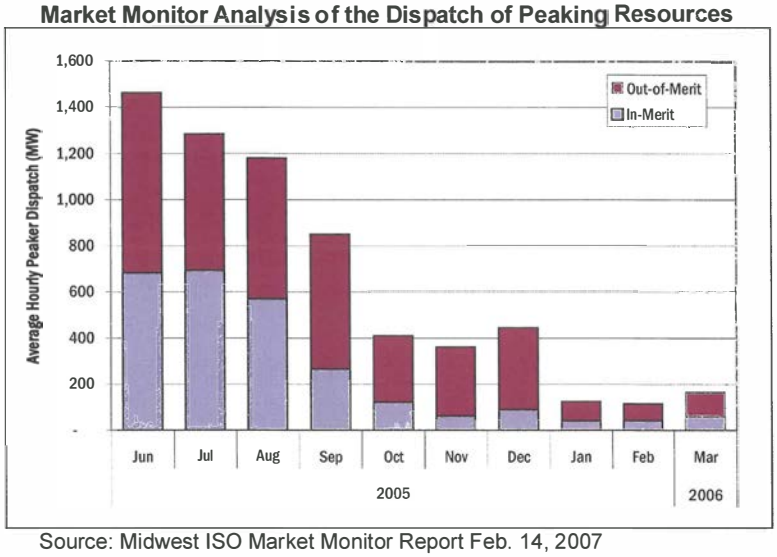
Comparison to Results in Similar Analyses

ICF's findings in this study are consistent with several previous analyses. Exhibit ES-6 is an excerpt from the Market Monitor report highlighting economic and non-economic peaking unit dispatch in the Midwest ISO. Summer 2005 shows large amounts of out-of-merit peaking dispatch. While there is less in October and December, it is still above 2006 levels. The lower 2006 levels support our findings of an improving trend. The combination of out-of-merit dispatch and extremely high fuel prices yields is consistent with the study results indicating negative benefits achieved during the months of October and December 2005. Note, that the 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.

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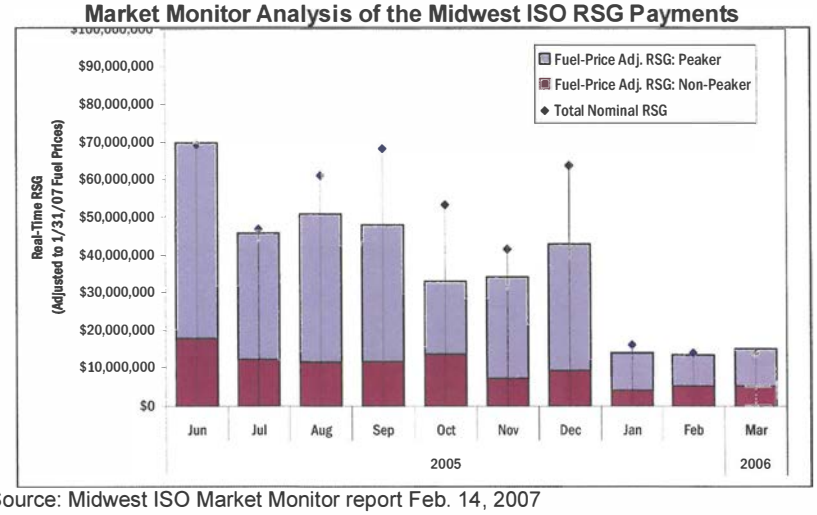
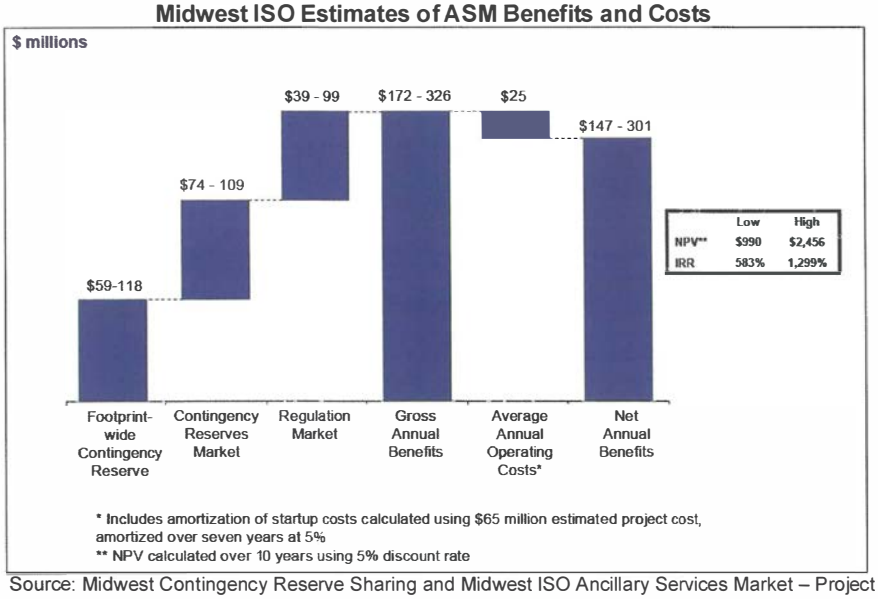
Exhibit 4-13:
Market Monitor Analysis of the Midwest ISO RSG Payments



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

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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.

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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

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$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.

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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

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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.

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

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FILE: Copy of CALCULATED MAGNETIC FIELD CHARTS.xls SHEET: milligauss TABLES 5/9/2014, 9:55 AM

ORIGINAL TABLE

TABLE 5.2-6. Calculated Magnetic Fields (milligauss) for proposed double circuit 345 kV Transmission Line Designs (3.28 feet above ground)

STRUCTURE TYPE	SYSTEM CONDITION	CURRENT (AMPS)	DISTANCE TO PROPOSED CENTERLINES												
			-300'	-200'	-100'	-75'	-50'	-25'	0'	25'	50'	75'	100'	200'	300'
1 CIRCUIT	PEAK	264	0.79	1.67	5.62	8.70	14.36	23.45	31.89	29.76	17.92	10.19	6.26	1.65	0.72
DELTA CFG	AVERAGE	158	0.47	1.00	3.36	5.21	8.60	14.03	19.08	17.81	10.73	6.10	3.75	0.99	0.43
1 CIRCUIT	PEAK	264	0.86	1.97	7.12	11.10	18.17	27.45	25.55	16.04	9.86	6.41	4.42	1.48	0.71
VERT CFG	AVERAGE	158	0.52	1.18	4.26	6.65	10.87	16.43	15.29	9.60	5.90	3.84	2.64	0.88	0.42
2 CIRCUIT W/	PEAK	264	0.71	1.48	4.43	6.43	9.89	16.09	25.62	27.50	18.18	11.10	7.11	1.97	0.86
1 CKT ACTIVE	AVERAGE	158	0.43	0.89	2.65	3.85	5.92	9.63	15.33	16.46	10.88	6.64	4.25	1.18	0.52
2 CIRCUIT W/	PEAK	264	0.19	0.58	3.32	6.08	11.96	22.90	30.03	23.06	12.10	6.17	3.39	0.59	0.19
2 CKTS ACTIVE	AVERAGE	158	0.11	0.35	1.99	3.64	7.16	13.71	17.97	13.80	7.24	3.70	2.03	0.35	0.12

MVA CALCULATED FROM CURRENT IN ORIGINAL TABLE:

345.00 kV
264.00 Amps PEAK
1.73 3 Phase
157.57 MVA PEAK CALC'D

345.00 kV
158.00 Amps AVERAGE
1.73 3 Phase
94.30 MVA AVERAGE CALC'D

ADJUSTABLE TABLE

TABLE 5.2-6. Calculated Magnetic Fields (milligauss) for proposed double circuit 345 kV Transmission Line Designs (3.28 feet above ground)

STRUCTURE TYPE	SYSTEM CONDITION	CURRENT (AMPS)	DISTANCE TO PROPOSED CENTERLINES												
			-300'	-200'	-100'	-75'	-50'	-25'	0'	25'	50'	75'	100'	200'	300'
1 CIRCUIT	PEAK	3434.70	10.28	21.73	73.12	113.19	186.83	305.09	414.90	387.18	233.14	132.57	81.44	21.47	9.37
DELTA CFG	AVERAGE	2513.19	7.48	15.91	53.45	82.87	136.79	223.17	303.49	283.29	170.67	97.03	59.65	15.75	6.84
1 CIRCUIT	PEAK	3434.70	11.19	25.63	92.63	144.41	236.40	357.13	332.41	208.68	128.28	83.40	57.51	19.26	9.24
VERT CFG	AVERAGE	2513.19	8.27	18.77	67.76	105.78	172.90	261.34	243.21	152.70	93.85	61.08	41.99	14.00	6.68
2 CIRCUIT W/	PEAK	3434.70	9.24	19.26	57.64	83.66	128.67	209.33	333.32	357.78	236.53	144.41	92.50	25.63	11.19
1 CKT ACTIVE	AVERAGE	2513.19	6.84	14.16	42.15	61.24	94.17	153.18	243.84	261.82	173.06	105.62	67.60	18.77	8.27
2 CIRCUIT W/	PEAK	3434.70	2.47	7.55	43.19	79.10	155.60	297.93	390.70	300.02	157.42	80.27	44.10	7.68	2.47
2 CKTS ACTIVE	AVERAGE	2513.19	1.75	5.57	31.65	57.90	113.89	218.08	285.84	219.51	115.16	58.85	32.29	5.57	1.91

ENTER MVA BELOW TO ADJUST CURRENT IN THE TABLE:

2050.00 MVA PEAK
345.00 kV
1.73 3 Phase
3434.70 Amps PEAK CALC'D

1500.00 MVA AVERAGE
345.00 kV
1.73 3 Phase
2513.19 Amps AVERAGE CALC'D