Frost Brown Todd LLC

ATTORNEYS

KENTUCKY · OHIO · INDIANA · TENNESSEE · WEST VIRGINIA

Mark David Goss
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MGOSS@FBTLAW.COM

RECEIVED
APR 08 2010
PUBLIC SERVICE COMMISSION

April 8, 2010

Via Hand-Delivery

Mr. Jeffrey Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of Its Transmission System to Midwest Independent Transmission System Operator, Inc.
PSC Case No. 2010-00043

Dear Mr. Derouen:

Enclosed please find herewith an original and nine (9) copies of Midwest Independent Transmission System Operator, Inc.'s Responses to KIUC's First Set of Data Requests to be filed in the above-referenced matter. Please return a file stamped copy to me for my file.

Please note from the original that is filed that several of the Response Exhibits contain charts and data summaries which are in color. Because of a copier machine problem, we were unable to provide color copies for some of the exhibits in all of the Response packages and they are instead, in black and white. Should Commission Staff desire to see the color version of these Exhibits, please let me know and I will be happy to forward same electronically. I will not do this unless requested by you as I do not want to fill your e-mail inbox with unwanted files.

Sincerely yours,

Mark David Goss

Enclosures

cc: Parties of Record

RECEIVED
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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC	)	
CORPORATION FOR APPROVAL TO	)	
TRANSFER FUNCTIONAL CONTROL OF ITS	)	**CASE NO. 2010-00043**
TRANSMISSION SYSTEM TO MIDWEST INDEPENDENT	)	
TRANSMISSION SYSTEM OPERATOR, INC.	)	

RESPONSES OF MIDWEST ISO TO FIRST SET OF DATA REQUESTS OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. (KIUC)
APRIL 7, 2010

VERIFICATION

I, Clair J. Moeller, Vice-President of Midwest Independent Transmission System Operator, Inc. verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this Verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Clair J. Moeller

STATE OF MINNESOTA)
COUNTY OF RAMSEY)

SUBSCRIBED AND SWORN TO before me by Clair J. Moeller on this 5th day of April, 2010.

LORI MADDOX
Notary Public-Minnesota
My Commission Expires Jan 31, 2015

Lori Maddox
Notary Public
My Commission Expires Jan 31, 2015

VERIFICATION

I, David Zwergel, Senior Director, Regional Operations of Midwest Independent Transmission System Operator, Inc. verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this Verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

David Zwergel

STATE OF INDIANA)
COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by David Zwergel on this 6th day of April, 2010.

Dorothy M. Shute
Notary Public
My Commission Expires 5-8-2017

DOROTHY M. SHUTE
Notary Public, State of Indiana
My County of Residence: Hendricks
My Commission Expires May 8, 2017

VERIFICATION

I, Richard Doying, Vice-President of Midwest Independent Transmission System Operator, Inc. verify, state, and affirm that I prepared or supervised the preparation of the data request responses filed with this Verification for which I am listed as a witness, and that those responses are true and accurate to the best of my knowledge, information, and belief formed after a reasonable inquiry.

Richard Doying

STATE OF INDIANA)
COUNTY OF HAMILTON)

SUBSCRIBED AND SWORN TO before me by Richard Doying on this 5th day of April, 2010.

Jennifer J Talbott

Jennifer Jo Talbott
Notary Public
My Commission Expires 09-06-15

MIDWEST ISO'S
RESPONSE TO KIUC'S
MARCH 26, 2010 FIRST DATA REQUEST
PSC CASE NO. 2010-00043
April 7, 2010

Item KIUC MISO 1-1) ***Please reference page 11 of your direct testimony. Please explain how the diversity of resources of MISO, as stated and alleged, will enable Big Rivers to reduce its energy costs. Do we understand your testimony to mean that Big Rivers will incur no transmission charges associated with its potential participation in MISO?***

Response) The diversity of resources within the Midwest ISO footprint provides Big Rivers the opportunity to optimize the use of its generation units with the rest of the units in the market. When the market price is lower than Big Rivers' cost of production, it can purchase energy from the market and save money. When the market price is higher than Big Rivers' cost of production, it can serve its needs from its own units and sell excess energy into the market at a profit. This is possible, because there are no additional transmission charges to export or import energy from the Big Rivers zone to or from another Midwest ISO zone. Big Rivers load will pay a single zonal rate, regardless of which resource actually provides the energy, and those revenues will be distributed to Big Rivers as the Transmission Owner, pursuant to the requirements of the Transmission Owners Agreement. The Big Rivers zonal transmission rate would be based on the current transmission charge already approved by the Kentucky PSC.

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-2) ***Please reference the top of page 13 of your testimony, which mentions the Value Proposition. Please provide Documents and Studies associated with the determination of the Value Proposition, as prepared by MISO.***

Response) All of the underlying documents demonstrating the calculations can be found on the Midwest ISO web site in electronic format, as indicated in my testimony. Copies of those documents are attached.

Witness) **Clair J. Moeller**

ATTACHMENT 1

MidwestISO
Energizing the Heartland

2009 Value Proposition
Direct Load Control (DLC) and Interruptibles Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$58	$56	$58	$391
High Estimate ($ in Mils.)	$72	$70	$73	$488

Assumptions	
2009 Peak Demand Forecast (MW)	98,559 [1]
Annual Inflation Rate	2.90% [2]
Discount Rate	9.50% [3]
Capital Cost ($/MW) - Low Estimate	800,000 [4]
Capital Cost ($/MW) - High Estimate	1,000,000 [4]

Calculation Detail - Realistic Achievable Potential, Low Estimate ($ in Mils.)

	A	B	C	D	E	F	G	H	I
Year	Projected Peak Demand (MW) [1]	Direct Load Control-Commercial, Industrial, & Residential - % of System Peak [5]	Interruptibles-Commercial, Industrial, & Residential - % of System Peak [5]	Total - % of System Peak (B + C)	Incremental Demand Response (MW) A X D	Benefit E X (Capital Cost - Low Estimate)	Incremental Benefit F Current Year - F Previous Year	Required Revenue Estimate [6]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98.559	0.89%	-0.17%	0.72%	711	$569	$569	$58	$58
2010	98.865	0.89%	-0.22%	0.67%	665	$532	($37)	($4)	$54
2011	101.353	0.91%	-0.20%	0.71%	720	$576	$44	$4	$59
2012	101.867	0.91%	-0.20%	0.71%	725	$580	$4	$0	$59
2013	102.235	0.86%	-0.25%	0.60%	618	$494	($86)	($9)	$50
2014	102.937	0.89%	-0.22%	0.67%	689	$551	$56	$6	$56
2015	103.760	0.89%	-0.23%	0.66%	683	$547	($4)	($0)	$56
2016	104,658	0.91%	-0.21%	0.70%	728	$582	$36	$4	$59
2017	105,575	0.91%	-0.21%	0.70%	734	$587	$5	$1	$60
2018	106,468	0.90%	-0.21%	0.69%	739	$591	$4	$0	$60

Calculation Detail - Maximum Achievable Potential, High Estimate ($ in Mils.)

	A	B	C	D	E	F	G	H	I
Year	Projected Peak Demand (MW) [1]	Direct Load Control-Commercial, Industrial, & Residential - % of System Peak [5]	Interruptibles-Commercial, Industrial, & Residential - % of System Peak [5]	Total - % of System Peak (B + C)	Incremental Demand Response (MW) A X D	Benefit E X (Capital Cost - High Estimate)	Incremental Benefit F Current Year - F Previous Year	Required Revenue Estimate [6]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98.559	0.89%	-0.17%	0.72%	711	$711	$711	$72	$72
2010	98.865	0.89%	-0.22%	0.67%	665	$665	($46)	($5)	$68
2011	101,353	0.91%	-0.20%	0.71%	720	$720	$55	$6	$73
2012	101,867	0.91%	-0.20%	0.71%	725	$725	$5	$1	$74
2013	102,235	0.86%	-0.25%	0.60%	618	$618	($107)	($11)	$63
2014	102.937	0.89%	-0.22%	0.67%	689	$689	$71	$7	$70
2015	103.760	0.89%	-0.23%	0.66%	683	$683	($5)	($1)	$69
2016	104,658	0.91%	-0.21%	0.70%	728	$728	$45	$5	$74
2017	105.575	0.91%	-0.21%	0.70%	734	$734	$6	$1	$75
2018	106,468	0.90%	-0.21%	0.69%	739	$739	$5	$0	$75

The Direct Load Control-Interruptible benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

MidwestISO
Energizing the Heartland

2009 Value Proposition
Direct Load Control (DLC) and
Interruptibles Benefit

Sources

[1] 2009-2018 Projected Peak Demand based on Midwest ISO 2009 Summer Assessment Net Internal Demand Forecast.

[2] 2 9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators Annual Growth 2007-2030 (percent) Wholesale Price Index (1982-1 00) Fuel and Power.

[3] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[4] High and Low Capital Costs based on an indicative capital cost values published by major industry participants

[5] The Brattle Group Report "Fostering Economic Response in the Midwest ISO", page 63 (Maximum Achievable Potential) and page 70 (Realistic Achievable Potential).

[6] Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only (20 year asset life and 9 5% weighted average cost of capital)

The Direct Load Control-Interruptible benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member

ATTACHMENT 2

MidwestISO
Energizing the Heartland

2009 Value Proposition
Dynamic Pricing Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$4	$33	$164	$546
High Estimate ($ in Mils.)	$7	$51	$256	$853

Assumptions	
2009 Peak Demand Forecast (MW)	98,559 [1]
Annual Inflation Rate	2 90% [2]
Discount Rate	9 50% [3]
Capital Costs ($/MW) - Low Estimate	800,000 [4]
Capital Costs ($/MW) - High Estimate	1,000,000 [4]

Calculation Detail - Realistic Achievable Potential, Low Estimate ($ in Mils.)

	A	B	C	D	E	F	G	H	I
Year	Projected Peak Demand (MW) [1]	Commercial & Industrial - % of System Peak [5]	Residential - % of System Peak [5]	Total - % of System Peak [6] (B + C) X 50%	Incremental Demand Response (MW) A X D	Benefit E X (Capital Costs - Low Estimate)	Incremental Benefit F Current Year - F Previous Year	Required Revenue Estimate [7]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98,559	0 02%	0 04%	0.05%	54	$43	$43	$4	$4
2010	98,865	0 05%	0 11%	0.15%	152	$121	$78	$8	$12
2011	101.353	0 13%	0 21%	0.34%	345	$276	$155	$16	$28
2012	101,867	0 23%	0 34%	0.57%	582	$466	$190	$19	$47
2013	102,235	0 35%	0 50%	0.85%	866	$693	$227	$23	$70
2014	102.937	0.47%	0 69%	1 17%	1.202	$962	$269	$27	$98
2015	103.760	0 62%	0 92%	1 53%	1,590	$1.272	$311	$32	$129
2016	104.658	0 77%	1 17%	1 94%	2.033	$1.626	$354	$36	$165
2017	105.575	0 94%	1.46%	2 40%	2.531	$2.024	$398	$40	$206
2018	106.468	1.02%	1.54%	2.55%	2,720	$2,176	$151	$15	$221

Calculation Detail - Maximum Achievable Potential, High Estimate ($ in Mils.)

	A	B	C	D	E	F	G	H	I
Year	Projected Peak Demand (MW) [1]	Commercial & Industrial - % of System Peak [5]	Residential - % of System Peak [5]	Total - % of System Peak [6] (B + C) X 50%	Incremental Demand Response (MW) A X D	Benefit E X (Capital Costs - High Estimate)	Incremental Benefit F Current Year - F Previous Year	Required Revenue Estimate [7]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98,559	0 04%	0.10%	0.07%	67	$67	$67	$7	$7
2010	98.865	0 11%	0.27%	0 19%	189	$189	$122	$12	$19
2011	101.353	0 33%	0.52%	0 43%	431	$431	$242	$25	$44
2012	101.867	0 58%	0.84%	0 71%	728	$728	$297	$30	$74
2013	102.235	0 87%	1 25%	1 06%	1.083	$1.083	$355	$36	$110
2014	102.937	1 19%	1 73%	1 46%	1.503	$1.503	$420	$43	$153
2015	103.760	1 54%	2 29%	1 92%	1.988	$1.988	$485	$49	$202
2016	104.658	1 92%	2 93%	2 43%	2.541	$2.541	$553	$56	$258
2017	105.575	2 34%	3.65%	3 00%	3.163	$3.163	$622	$63	$322
2018	106,468	2.54%	3.85%	3.19%	3,400	$3,400	$236	$24	$346

The Dynamic Pricing benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member

2009 Value Proposition
Dynamic Pricing Benefit

Sources

[1] 2009-2018 Projected Peak Demand based on Midwest ISO 2009 Summer Assessment Net Internal Demand Forecast
[2] 2 9% - EIA 2009 Annual Energy Outlook Page 39, Table A20 Macroeconomic Indicators Annual Growth 2007-2030 (percent) Wholesale Price Index (1982-1 00) Fuel and Power
[3] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest
[4] High and Low Capital Costs based on an indicative capital cost values published by major industry participants
[5] The Brattle Group Report "Fostering Economic Response in the Midwest ISO", page 63 (Maximum Achievable Potential) and page 70 (Realistic Achievable Potential)
[6] The Total % of System Peak was multiplied by 50% to arrive at a high estimate
[7] Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only (30 year asset life and 9 5% weighted average cost of capital)

ATTACHMENT 3

MidwestISO
Energizing the Heartland

2009 Value Proposition
Dispatch of Energy Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$210	$222	$257	$1,613
High Estimate ($ in Mils.)	$264	$280	$323	$2,028

Assumptions	
Annual Inflation Rate	2.90% [1]
Discount Rate	9.50% [2]

Calculation Detail ($ in Mils.)

Year	Dispatch of Energy Low Estimate [3]	Dispatch of Energy High Estimate [3]
2009	$210	$264
2010	$216	$272
2011	$222	$280
2012	$229	$288
2013	$235	$296
2014	$242	$305
2015	$249	$313
2016	$256	$323
2017	$264	$332
2018	$272	$342

The Dispatch of Energy benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

MidwestISO
Energizing the Heartland

2009 Value Proposition
Dispatch of Energy Benefit

Sources

[1] 2.9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators. Annual Growth 2007-2030 (percent). Wholesale Price Index (1982-1.00). Fuel and Power.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] The ICF study examined market performance from June 2005 to August 2006. To account for market maturity, our analysis only considered data for 2006 and annualized the results. January-August results were annualized assuming that benefits would accrue at the same rate from September through December.

Dispatch Benefits (in 2006 Dollars)

	Jan - Aug, 2006	Annualized 2006 Total
Actual	133	200
Estimated	167	251

Dispatch Benefits (Adjusted to reflect 2009 dollars-See Note #1)

	Jan - Aug, 2006	Annualized 2006 Total
Actual	140	210
Estimated	176	264

2007	3.1%
2008	10.2%
2009	-7.4%

Note #1 - Inflation Rate from Actual PPI from Bureau of Labor Statistics based on Electric Power Generation industry. Actual PPI for 2009 is thru August 2009 only. Actual PPI thru August 2009 was assumed to be indicative of the Actual PPI for the entire 2009 year.

ATTACHMENT 4

MidwestISO
Energizing the Heartland

2009 Value Proposition
Footprint Diversity Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$217	$222	$231	$1,546
High Estimate ($ in Mils.)	$272	$277	$288	$1,932

Assumptions		
2009 Peak Demand Forecast (MW)	98,559	[1]
Required Planning Res Margin - Without RTO/ISO	15.40%	[2]
Required Planning Res Margin - With RTO/ISO	12.69%	[2]
Discount Rate	9.50%	[3]
Capital Costs ($/MW) - Low Estimate	800,000	[4]
Capital Costs ($/MW) - High Estimate	1,000,000	[4]

Calculation Detail - Low Estimate ($ in Mils.)

	A	B	C	D	G	H	I
Year	Projected Peak Demand (MW) [1]	Load Diversity [5]	Required Capital Investment (MW) A X B	Required Capital Investment C X [Capital Costs - Low Estimate]	Incremental Benefit $D_{Current Year}$ - $D_{Previous Year}$	Required Revenue Estimate [6]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98,559	2.71%	2,671	$2,137	$2,137	$217	$217
2010	98,865	2.71%	2,679	$2,143	$7	$1	$218
2011	101,353	2.71%	2,747	$2,197	$54	$5	$223
2012	101,867	2.71%	2,761	$2,208	$11	$1	$225
2013	102,235	2.71%	2,771	$2,216	$8	$1	$225
2014	102,937	2.71%	2,790	$2,232	$15	$2	$227
2015	103,760	2.71%	2,812	$2,250	$18	$2	$229
2016	104,658	2.71%	2,836	$2,269	$19	$2	$231
2017	105,575	2.71%	2,861	$2,289	$20	$2	$233
2018	106,468	2.71%	2,885	$2,308	$19	$2	$235

Calculation Detail - High Estimate ($ in Mils.)

	A	B	C	D	G	H	I
Year	Projected Peak Demand (MW) [1]	Load Diversity [5]	Required Capital Investment (MW) A X B	Required Capital Investment C X [Capital Costs - High Estimate]	Incremental Benefit $D_{Current Year}$ - $D_{Previous Year}$	Required Revenue Estimate [6]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98,559	2.71%	2,671	$2,671	$2,671	$272	$272
2010	98,865	2.71%	2,679	$2,679	$8	$1	$272
2011	101,353	2.71%	2,747	$2,747	$67	$7	$279
2012	101,867	2.71%	2,761	$2,761	$14	$1	$281
2013	102,235	2.71%	2,771	$2,771	$10	$1	$282
2014	102,937	2.71%	2,790	$2,790	$19	$2	$284
2015	103,760	2.71%	2,812	$2,812	$22	$2	$286
2016	104,658	2.71%	2,836	$2,836	$24	$2	$288
2017	105,575	2.71%	2,861	$2,861	$25	$3	$291
2018	106,468	2.71%	2,885	$2,885	$24	$2	$293

The Footprint Diversity benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member

2009 Value Proposition
Footprint Diversity Benefit

Sources

[1] 2009-2018 Projected Peak Demand based on Midwest ISO 2009 Summer Assessment Net Internal Demand Forecast.
[2] 15.4% and 12.69% planning reserve margins based on Midwest ISO's Module E requirements.
[3] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.
[4] High and Low Capital Costs based on an indicative capital cost values published by major industry participants.
[5] 2.71% is the difference between 15.4% planning reserve margin without Midwest ISO and 12.69% planning reserve margin with Midwest ISO.
[6] Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only (30 year asset life and 9.5% weighted average cost of capital).

ATTACHMENT 5

MidwestISO
Energizing the Heartland

2009 Value Proposition
Generator Availability Improvement Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$249	$254	$264	$1,768
High Estimate ($ in Mils.)	$311	$317	$330	$2,210

Assumptions		
2009 Peak Demand Forecast (MW)	98,559	[1]
Discount Rate	9.50%	[2]
Capital Costs ($/MW) - Low Estimate	800,000	[3]
Capital Costs ($/MW) - High Estimate	1,000,000	[3]
Generator Availability Improvement	3.1%	[4]

Calculation Detail - Low Estimate ($ in Mils.)

	A	B	C	D	G	H	I
Year	Projected Peak Demand (MW) [1]	Generator Availability Improvement [4]	Required Capital Investment (MW) A X B	Required Capital Investment C X [Capital Costs - Low Estimate]	Incremental Benefit $D_{Current Year}$ - $D_{Previous Year}$	Required Revenue Estimate [5]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98,559	3.10%	3,055	$2,444	$2,444	$249	$249
2010	98,865	3.10%	3,065	$2,452	$8	$1	$249
2011	101,353	3.10%	3,142	$2,514	$62	$6	$256
2012	101,867	3.10%	3,158	$2,526	$13	$1	$257
2013	102,235	3.10%	3,169	$2,535	$9	$1	$258
2014	102,937	3.10%	3,191	$2,553	$17	$2	$260
2015	103,760	3.10%	3,217	$2,573	$20	$2	$262
2016	104,658	3.10%	3,244	$2,596	$22	$2	$264
2017	105,575	3.10%	3,273	$2,618	$23	$2	$266
2018	106,468	3.10%	3,301	$2,640	$22	$2	$268

Calculation Detail - High Estimate ($ in Mils.)

	A	B	C	D	G	H	I
Year	Projected Peak Demand (MW) [1]	Generator Availability Improvement [4]	Required Capital Investment (MW) A X B	Required Capital Investment C X [Capital Costs - High Estimate]	Incremental Benefit $D_{Current Year}$ - $D_{Previous Year}$	Required Revenue Estimate [5]	Cumulative Required Revenue Estimate Current Year (H) + Prior Year Cumulative Total (I)
2009	98,559	3.10%	3,055	$3,055	$3,055	$311	$311
2010	98,865	3.10%	3,065	$3,065	$9	$1	$312
2011	101,353	3.10%	3,142	$3,142	$77	$8	$319
2012	101,867	3.10%	3,158	$3,158	$16	$2	$321
2013	102,235	3.10%	3,169	$3,169	$11	$1	$322
2014	102,937	3.10%	3,191	$3,191	$22	$2	$324
2015	103,760	3.10%	3,217	$3,217	$26	$3	$327
2016	104,658	3.10%	3,244	$3,244	$28	$3	$330
2017	105,575	3.10%	3,273	$3,273	$28	$3	$333
2018	106,468	3.10%	3,301	$3,301	$28	$3	$336

The Generator Availability Improvement benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

2009 Value Proposition
Generator Availability Improvement Benefit

Sources

[1] 2009-2018 Projected Peak Demand based on Midwest ISO 2009 Summer Assessment Net Internal Demand Forecast.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] High and Low Capital Costs based on an indicative capital cost values published by major industry participants.

[4] Generator Availability Data System (GADS) – 2000 to 2008.

[5] Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only (30 year asset life and 9.5% weighted average cost of capital).

ATTACHMENT 6

Midwest ISO
Energizing the Heartland

2009 Value Proposition
Improved Reliability Benefit Calculation Walkthrough

Note: This document does not intend to provide a detailed step-by-step approach to calculating the benefit, but serves to provide a high-level overview of the benefit calculation.

1. Original disturbance data is from 2000 to 2007 and was provided directly by NERC. The data contains more detailed information than the public version available on NERC's website. The public version can be found at: http://www.nerc.com/page.php?cid=5|66. See modified NERC database called "NERC Database-Midwest ISO 2009 Value Proposition.pdf" in the benefit calculation detail section.
2. Each disturbance was analyzed to identify/calculate the following attributes:
   a. Identified if disturbance occurred in a RTO region vs. a non-RTO region based on the provided "Associated Utilities" and "Region ID" data in the NERC database. See the classifications in the "In RTO Region?" field of the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file.
   b. Calculated the length of the disturbance based on the provided "Disturbance Start Date & Time" and "Restoration Time" data provided in the NERC database. See the results in the "Disturbance Duration (Hours)" field of the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file. The "Restoration Time" field was not provided in order to limit the size of the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file.
   c. "Disturbance Duration (Hours)" and "Disturbance Size (MW)" data of the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file was supplemented with Energy Information Administration (EIA) disturbance data using the following rules:
      i. If a NERC disturbance had values for "Disturbance Duration (Hours)" and "Disturbance Size (MW)", the NERC data was used even if there was a difference with the EIA disturbance data (i.e. if a NERC disturbance had 10 disturbance duration hours and a corresponding EIA disturbance had 12 disturbance duration hours, NERC's disturbance data was used).
      ii. If a NERC disturbance had N/As for one or more of "Disturbance Duration (Hours)" and "Disturbance Size", the EIA disturbance data was used (i.e. if a NERC disturbance has N/A for "Disturbance Duration (Hours)" and a corresponding EIA disturbance had 12 disturbance duration hours, EIA's disturbance data was used).
      iii. If EIA had a disturbance that wasn't included in the NERC database, it was not added to the NERC data as the disturbance description provided by EIA is insufficient to determine whether it is a transmission or a distribution level event.
      iv. If EIA disturbance data provided a range, the lowest value was used.
   d. In the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file, disturbances were grouped together where applicable for benefit calculation purposes to form events. For example, if a weather event affected multiple utilities, those individual disturbances reflecting that specific weather event would be combined to form a unique event. Please note that the provided "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file includes ALL individual disturbances that were provided to the Midwest ISO.

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3. Disturbances were excluded from the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file using various data filters.
    a. The "Primary Filter" field excludes disturbances (as shown by a "N") under the following circumstances:
        i. "Disturbance Duration (Hours)" was incomplete so a disturbance duration could not be calculated
        ii. "Disturbance size (MW)" was not available
        iii. The "Disturbance Type" field had one of the following attributes: Voltage Reduction (VR), Demand Reduction (DR), Public Appeal (PA), Operating Security Limit (OSL), or N/A.
        iv. The "Disturbance Type" field was marked Customer Interruption (INT) AND the "Disturbance Cause" field had one of the following attributes: Energy Emergency Alert (EEA), Fuel Supply Problems, or Vandalism.
        v. The "Disturbance Type" field was marked Unusual Occurrence (UO) AND the "Disturbance Cause" had one of the following attributes: Cyber Failure, Vandalism, Fuel Supply Problems, Suspicious Surveillance Activities, or EMS Computer Failure.
    b. The "Secondary Filter" field excludes disturbances (as shown by an "N") based on a careful review of the "Event Description" provided by NERC.
    c. The "Threshold Filter" field excludes events when the number of "Customers Interrupted" equaled or exceeded 1,000,000 and/or durations equaled or exceeded one week (168 hours) as it was assumed those characteristics fit the profile of a distribution-level event.
4. "MWh Interrupted" of the "NERC Database-Midwest ISO 2009 Value Proposition.pdf" file was calculated for each disturbance/event by performing the following calculation: "Disturbance Duration (Hours)" X "Disturbance Size (MW)" X load loss profile of 0.67.
    a. The sum of "MWh Interrupted" for each region is as follows:
        i. Non-RTO region = 832,768 MWh
        ii. RTO region = 422,056 MWh
    b. These values were then divided by 8 (i.e. the number of years in the NERC database) to arrive at an average MWh per year:
        i. Non-RTO region = 104,096 MWh
        ii. RTO region = 52,757 MWh
5. Energy Information Administration, EIA-826 Database for 2008 was used to calculate the MWh Load Served for the RTO, Non-RTO, and Midwest ISO region. EIA-826 database can be found at: http://www.eia.doe.gov/cneaf/electricity/page/eia826.html. Each utility in EIA-826 was classified as a utility located in an RTO or non-RTO region. If the utility was in an RTO region, it was classified as a Midwest ISO region or non-Midwest ISO region. The sum of MWh Load Served for each region for 2008 is as follows:
    a. Non-RTO region = 1,482,493,088 MWh
    b. RTO region = 2,253,220,087 MWh
    c. Midwest ISO region = 647,538,321 MWh

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6. The following is the Transmission System Availability Index (TSAI) calculation:

$$1 - \left(\frac{\text{Sum of MWh Load Interrupted}}{\left(\begin{array}{c} \text{Sum of MWh Load Interrupted} \\ + \\ \text{Sum of MWh Load Served} \end{array} \right)} \right)$$

   a. Non-RTO TSAI = 99.992979%
   b. RTO TSAI = 99.997659%
7. The difference between the Non-RTO and RTO region TSAI was calculated (0.004680%) and multiplied by the Midwest ISO Load Served (647,538,321 MWh) and the economic cost of outage ($12,999) to arrive at the improved reliability benefit (only high estimate shown).
   a. Difference in TSAI (0.004680%) X Midwest ISO load (647,538,321 MWh) X Economic Cost of Outage ($12,999 per MWh) = Total Improved Reliability high estimate benefit ($393,925,654)

ATTACHMENT 7

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	Year 1	10-Year NPV
Low Estimate ($ in Mils.)	$263	$2,017
High Estimate ($ in Mils.)	$394	$3,026

Assumptions	
Annual Inflation Rate	2.90% [1]
Discount Rate	9.50% [2]

Calculation Detail ($ in Mils.)

	A	B	C	D	E	F	G	H	I	J		
Year	RTO Load Interrupted (MWh) [3]	RTO Load Served (MWh) [4]	RTO TSAI 1-[A/(A+B)]	Non-RTO Load Interrupted (MWh) [3]	Non-RTO Load Served (MWh) [4]	Non-RTO TSAI 1-[D/(D+E)]	TSAI Difference C - F	Midwest ISO Load Served (MWh) [5]	Economic Cost of Outage - Low [6]	Economic Cost of Outage - High [6]	Benefit Low Estimate G X H X I	Benefit High Estimate G X H X J
2009	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$8,666	$12,999	$263	$394
2010	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$8,918	$13,376	$270	$405
2011	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$9,176	$13,764	$278	$417
2012	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$9,442	$14,163	$286	$429
2013	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$9,716	$14,574	$294	$442
2014	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$9,998	$14,997	$303	$454
2015	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$10,288	$15,432	$312	$468
2016	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$10,586	$15,879	$321	$481
2017	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$10,893	$16,340	$330	$495
2018	52,757	2,253,220,087	99.997659%	104,096	1,482,493,088	99.992979%	0.004680%	647,538,321	$11,209	$16,813	$340	$510

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Sources

[1] 2.9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators. Annual Growth 2007-2030 (percent). Wholesale Price Index (1982-1.00). Fuel and Power.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] RTO/Non-RTO Load Interrupted is the sum of the "MWh Interrupted" column in the NERC Database for those disturbances that occurred in a RTO/Non-RTO region divided by 8 (i.e. the number of years in the NERC Database).

[4] RTO/Non-RTO Load Served was derived from EIA Database 826 for 2008 by summing all MWh sales attributable to RTO/Non-RTOs in the United States.

[5] Midwest ISO Load Served was derived from EIA Database 826 for 2008 by summing all MWh sales attributable to Midwest ISO in the United States.

[6] ICF, "The Economic Cost of the Blackout." The ICF paper defined a cost of outage range to be 80 to 120 times the retail price of electricity. This range is supported by survey-based studies that estimate an electric consumer's (i.e. residential, commercial, industrial, and others) willingness-to-pay to avoid such outages. The retail price was adjusted to 2009 dollars using Actual CPI from the Bureau of Labor Statistics.

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ATTACHMENT 8

2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
1/3/2000 22:48	2.8	Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	INT	60,000	326	Weather	During a period of high winds and freezing rain system protection removed from service a radial transmission circuit at 2248 EST. At 2250, system protection removed from service a second transmission circuit interrupting 326 MW of demand. The radial circuit was returned to service at 0056 EST on January 4. Demand restoration was completed at 0136. The second circuit remained unavailable pending inspection.	Y	Y		Y	612
1/23/2000 8:00	124.0	Duke Power Company	SERC-VACAR	Y	N	N	INT	133,000	450	Weather - Snow and Ice storm	In the early morning hours of Sunday, January 23, a winter storm that started out as snow and transitioned to sleet/freezing rain struck the Duke Power Company service territory. Customer outages totaled 109,000 by midnight, January 24. As of 0833 EST on January 24, about 58,000 customers were still without service. Most of these customers were in the Anderson, and Greenville, South Carolina areas. The entire Duke Power service territory experienced additional snow and high winds on Monday, January 24, resulting in additional customer outages. Customer outages during the storm peaked at 133,000 at 1100 EST on Tuesday the 25. With the exception of scattered customer outages, service to all customers was restored by 1620 EST, Friday, January 28.	Y	Y		Y	37,386
1/24/2000 4:39	89.0	Dairyland Power Coop.	MAPP	Y	N	N	UO	0	N/A	Equipment failure	When the Genoa No. 3 coal-fired unit was synchronized to the bus, the unit's oil circuit breaker failed. The breaker appears to have been stuck in a partially closed position with contacts physically separated but apparently holding full voltage at various times during the event. System protection opened circuit breakers at Northern States Power Company's (NSP) Coulee station, Alliant's Lansing and Nelson Dewey stations, and Dairyland Power Cooperative's (DPC) Bell Center and Harmony stations. Five fault events were detected by digital relays at DPC's Caledonia and NSP's Coulee stations. These events occurred during a 5.4 second period. At 0440, the center tank of the unit breaker exploded, which activated the bus differential at Genoa clearing the fault. In addition, the explosion caused bus supports to crack resulting in an extended outage. The line was returned to service at 0650. Genoa No. 3 was returned to service at 2140 on January 27 after the unit breaker was replaced. Customers were not affected by the event. After the fact, Dairyland determined an operating security limit violation occurred between 0440 to 0650. DPC's real-time security analysis did not identify this problem at the time and is investigating why.	N	N	No FIRM demand interruption reported	Y	
1/24/2000 17:00	31.0	South Carolina Electric & Gas Co.	SERC-VACAR	Y	N	N	INT	62,000	N/A	Weather	The severe winter storm, which affected Duke Power beginning on January 23, moved into the South Carolina Electric & Gas service territory on January 24. System protection removed three 115 kV transmission lines from service due to storm conditions. The lines were restored to service by midnight, January 25. Electric service to all customers was restored by 1200 EST on January 26.	N	N	No FIRM demand interruption reported	Y	
1/24/2000 19:00	137.0	Carolina Power & Light Co.	SERC-VACAR	Y	N	N	INT	173,000	960	Weather	A winter storm, starting as freezing rain and sleet, moved into the Carolina Power & Light Company service area on Monday evening, January 24, around 1900 EST. By Tuesday, January25, the storm dumped more than 20 inches of snow and left 173,000 customers without electric service. Downed trees and distribution lines hampered restoration of service, making roads impassible in the hardest hit areas. The storm also caused interruptions on four transmission lines. Following the storm, electricity was restored to 78% of the affected customers within the first 24 hours and more than 90% were restored within three days. Service was restored to essentially all customers capable of receiving service by 1200 EST on January 30. Final restoration was hampered by a second winter storm which hit the same area on January 29-30.	Y	Y		Y	88,118
1/29/2000 22:00	110.0	Duke Power Company	SERC-VACAR	Y	N	N	INT	81,000	300	Weather	On Saturday, January 29, 2000, a winter storm brought sleet/freezing rain to the Duke Power Company service territory during the late evening of January 29 and continued through the early evening of January 30. The number of customers without electric service peaked at about 81,000 at 2000 hours EST on January 30. Most of these customers were in the Charlotte, North Carolina and upstate South Carolina areas. By 1300 EST on January 31, the number of customers without service was reduced to about 40,000 in the Charlotte, Salisbury, and Greensboro/High Point/Burlington areas of North Carolina and the Greenwood County, South Carolina area. By 1200 EST, February 3, electric service was restored to all customers.	Y	Y		Y	22,110
2/2/2000 15:15	0.1	Otter Tail Power Co.	MAPP	Y	Y	Y	INT	20,000	100	Human Error	On Wednesday, February 2, 2000 personnel working in the Donaldson 115 kV substation were replacing system protection panels. Just prior to 1515 CST, a technician energized a 125 Vdc motor circuit, opening the motor-operated switch connected to it. The switch is not capable of breaking normal electrical flows on this line, and a phase-to-phase fault occurred as it opened. Circuit breakers one bus back from Donaldson cleared the fault. The arcing horn on the switch was the only reported equipment damage. The motor-operated switch is part of an auto-sectionalizing scheme for a 115 kV line and was timed to open between circuit breaker reclose attempts. Normal system protection for this fault had been disabled at Donaldson, due to the maintenance work.The disturbance also caused a separation between MAPP – US and Manitoba when a 230 tie line opened at 1515 CST, and the Manitoba Hydro HVDC reduction scheme correctly reduced generation in response to this disturbance. The separation ended at 1520 CST when Manitoba Hydro closed the line.Minnkota Power Coop will investigate why system protection opened the 230 kV line.	Y	Y		Y	6

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Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
2/26/2000 7:04	0.3	Southern California Edison Co.	WECC-CAMX	Y	Y	N	Int	112,000	300	Operator error	On Wednesday, February 2, 2000 personnel working in the Donaldson 115 kV substation were replacing system protection panels. Just prior to 1515 CST, a technician energized a 125 Vdc motor circuit, opening the motor-operated switch connected to it. The switch is not capable of breaking normal electrical flows on this line, and a phase-to-phase fault occurred as it opened. Circuit breakers one bus back from Donaldson cleared the fault. The arcing horn on the switch was the only reported equipment damage. The motor-operated switch is part of an auto-sectionalizing scheme for a 115 kV line and was timed to open between circuit breaker reclose attempts. Normal system protection for this fault had been disabled at Donaldson, due to the maintenance work.The disturbance also caused a separation between MAPP – US and Manitoba when a 230 tie line opened at 1515 CST, and the Manitoba Hydro HVDC reduction scheme correctly reduced generation in response to this disturbance. The separation ended at 1520 CST when Manitoba Hydro closed the line.Minnkota Power Coop will investigate why system protection opened the 230 kV line.	Y	N	No valid description - this is for the Otter Tail event on 2/2/00	Y	57
3/17/2000 12:13	1.0	Nevada Power Company	WECC-AZNMSNV	Y	N	N	INT	N/A	40	Operator Error	A Southern California Edison Company technician was performing maintenance on the under-frequency relays at the Mohave Generating Station at about 1213 PST on Friday, March 17. The technician inadvertently opened two 500/69 kV transformers This event caused electricity outages to the City of Laughlin and the Needles area for about one hour and 3 minutes.	Y	Y		Y	28
3/18/2000 15:57	18.9	El Paso Electric Co. and Public Service Co. of New Mexico	WECC-AZNMSNV	Y	N	N	DR	600,000	1,590	Brush fire	Prior to this disturbance, Public Service Company of New Mexico's (PNM) 345 kV San Juan Generating Station – Ojo Switching Station line was out of service so a static ground wire could be replaced. A brush fire near and beneath a PNM transmission corridor about four miles south of the Four Corners Generating Station caused system protection to open the 345 kV San Juan Generating Station – BA Switching Station and the Four Corners Generating Station – West Mesa Switching Station lines, and the230 kV Four Corners Generating Station – Pillar Switching Station line. The dispatchers tested and tried to restore the 345 kV lines to service, but were not successful. PNM dispatchers initiated manual load shedding. Voltages in the area continued to sag causing under-voltage load shedding in addition to the manual load shedding implemented by EPE and PNM dispatchers. At about 1643, system protection removed from service EPE's 180 MW Newman Generating Unit No. 4. PNM and EPE continued shedding load to restore stability to their systems. At 1649, Texas-New Mexico Power Company shed 60 MW of interruptible demand. At 1718, the EPE 345 kV Arroyo Switching Station – West Mesa Switching Station line opened as did the 115 kV PNM and Plains Electric G&T Coop lines leaving central and northern New Mexico customers without electricity. EPE restored electric service to its customers by about 1720.	N	Y		Y	20,152
3/21/2000 20:46	0.4	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	INT	0	N/A	Unknown	System protection opened Pole No. 1 of the Radisson – Sandy Pond HVDC interconnection between Québec and New England at Radisson and Sandy Pond at 2046 EST on Tuesday, March 21, 2000. ISO New England reported a problem on the communication system at Sandy Pond, which may have caused the system protection to operate. The incident is being investigated.	N	N	No FIRM demand interruption reported	Y	
4/1/2000 8:52	1.5	City of Lake Worth Utilities	FRCC	Y	N	N	INT	24,000	46	Equipment failure	On Saturday, April 1, 2000, at 0852 EST, a potential transformer at the Hypoluxo Substation failed, causing all circuit breakers at the station to open. This action separated the City of Lake Worth from the rest of Florida. Lake Worth's remaining generating resources were insufficient to supply the demand, resulting in a drop in frequency and system protection subsequently removed the Lake Worth generating facility from service. Due to routine maintenance being performed at the time, Florida Power & Light Company had the electric supply interrupted to three substations, which also were supplied through the Hypoluxo Substation.	Y	Y		Y	45
4/1/2000 16:47	0.9	Virginia Power	SERC-VACAR	Y	Y	N	INT	37,000	143	Equipment failure	A high-voltage bushing on OX substation transformer No. 3, failed and faulted to ground, causing a fire at 1647 EST on Saturday, April 1, 2000. The transmission lines supplying the station were de-energized to permit fire fighting. Customer outages ranged from eight to 56 minutes.	Y	Y		Y	86
4/20/2000 22:04	N/A	Manitoba Hydro	MAPP-Canada	Y	Y	Y	UO	0	N/A	Equipment failure	At 22:04 CST, system protection opened a Forbes capacitor circuit breaker. Also a Forbes circuit breaker failed to open and initiated a breaker fail protection scheme, which activated the Forbes Static Var Compensation System (SVS) and correctly initiated an HVDC reduction. Due to a design flaw in the HVDC reduction system at the Forbes Substation, a total of six subsequent HVDC reductions occurred between 22:04 and 22:21 as flows on the line reached the activation threshold. The HVDC reductions occurred as Manitoba Hydro attempted to restore tie line flows to normal. At 22:21 Manitoba Hydro called upon 300 MW of MAPP emergency energy, to replace scheduled flows.	N	N	No FIRM demand interruption reported	Y	
5/2/2000 4:00	19.0	Reliant Energy HL&P	ERCOT	Y	Y	N	INT	238,000	N/A	Severe weather	A line of strong thunderstorms entered the Reliant Energy HL&P service area on May 2, 2000 at about 0400 CDT. Strong winds, heavy rain and lightning caused outages on an estimated 182 circuits, interrupting service to 238,000 customers at the peak of the storm. Reliant Energy HL&P restored electric service to all but 27,000 customers by 1700 CDT. It restored service to the remaining customers by 2300 CDT.	N	Y		Y	

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
5/8/2000 13:45	4.4	Connectiv, Inc.	MAAC	Y	Y	N	VR	N/A	N/A	High demand/capacity shortage	Conectiv Power Delivery initiated a 5% system wide voltage reduction to comply with PJM emergency procedures on Monday, May 8, 2000at 1345 EDT. PJM initiated a system wide voltage reduction in response to unseasonably high temperatures, exceeding 90 F, which resulted in high demand and a capacity shortage across the PJM system. Normal voltage was restored at 1808 EDT.	N	N	Voltage reduction	Y	
5/9/2000 11:39	5.9	Consolidated Edision of NY and NY ISO	NPCC_NYISO	Y	Y	N	PA	N/A	N/A	Operating reserve shortage	The New York Independent System Operator requested member utilities to make public appeals to conserve energy on May 9, 2000 at 1139 EDT. The public appeal was due to a statewide shortage of operating reserve. The alert was terminated at 1735 EDT.	N	N	Public Appeal	Y	
5/18/2000 18:00	N/A	Commonwealth Edison Co.	MAIN	Y	Y	Y	INT	50,000	N/A	Severe weather	Severe thunderstorms accompanied by high winds moved through the ComEd service territory causing distribution system damage on May 18, 2000 at about 1800 CDT. Service was interrupted to about 50,000 customers for three hours or more.	N	Y		Y	
5/20/2000 23:00	41.0	Duke Power Company	SERC-VACAR	Y	N	N	INT	50,000	200	Severe wather	Thunderstorms with lightening moved into the Duke Power Company service territory, interrupting service to about 50,000 customers on May 20, 2000 at about 2300. By 1100 EDT on May 21, the number of customers without service was reduced to 1500. Electric service to all remaining customers was restored by 1600 EDT on May 22.	Y	Y		Y	5,494
5/25/2000 10:00	133.0	Duke Power Company	SERC-VACAR	Y	N	N	INT	147,000	500	Severe weather	A band of thunderstorms cut across the Duke Power Company service territory, hitting the Greensboro, NC and Alamance County, NC areas at about 1000 EDT on May 25, 2000. Service to 147,000 customers was interrupted at the peak of the storms. By 1500 EDT on May 26, the number of customers out of service was reduced to 119,200. By 1200 EDT on May 27, the number of customers without service was reduced to 57,000. Service to all remaining customers was restored by 2300 EDT on May 30.	Y	Y		Y	44,555
5/25/2000 10:15	7.7	Entergy	SPP	Y	Y	N	PA	N/A	N/A	Capacity shourtage, high temperatures	Entergy issued a public appeal asking customers to voluntarily reduce their usage of electricity at 1015 CDT on May 25, 2000 because demand was reaching the limits of available supply. Contributing to the tight capacity supply situation were storms that damaged both Entergy's and neighboring utilities' transmission systems, unusually high temperatures for the time of year, and unit outages due to planned maintenance. The public appeal was cancelled at 1800 CDT.	N	N	Public Appeal	Y	
6/9/2000 6:55	0.0	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	INT	1	50	Switching error	A switching error at the Premiere Chute substation created an inadvertent parallel between the Ontario system and the Hydro Quebec system at 0655 EDT on June 9, 2000. Service to one customer (50 MW) was briefly interrupted. Normal conditions were restored at 0658 EDT.	Y	Y		Y	2
6/9/2000 7:32	1.9	Manitoba Hydro	MAPP-Canada	Y	Y	Y	INT	N/A	N/A	Human error	System protection opened all Shannon 230 kV breakers inadvertently at 0732 CDT, while performing breaker failure checks at Shannon substation. The cause was due to a jumper, which was erroneously left on the breaker failure circuitry during a previous test procedure. The event initiated an HVDC reduction of 61 MW. The line on which the jumper was placed was returned to service at 09:27.	N	N	No FIRM demand interruption reported	Y	
6/14/2000 13:13	3.3	California Independent System Operator	WECC-CAMX	Y	Y	N	DR	32,000	130	Capacity shortage	A Stage 1 Emergency was declared at 1313 PDT on June 14, 2000 for the San Francisco Greater Bay Area due to a lack of 979 MW of generating resources and declining local area voltages. To avoid the possibility of a voltage collapse, blocks of about 130 MW of firm demand were shed for about one hour then restored in rotating fashion. About 500 MW of interruptible also was shed. The Stage 1 Emergency was cancelled at 1630 PDT.	N	N	Capacity Issue	Y	286
6/14/2000 15:45	0.2	American Electric Power	ECAR	Y	Y	N	INT	N/A	294	Equipment failure	A three-phase fault occurred on a 13 kV feeder at 1545 PDT on June 14, 2000. Due to a system protection malfunction, the fault was not cleared for 19 cycles resulting in the loss of 294 MW of demand. Electric service was restored by 1600 EDT.	Y	Y		Y	49
6/14/2000 15:54	1.1	Tucson Electric Power Company	WECC-AZNMSNV	Y	N	N	DR	40,911	138	Fire	A fire of unknown origin passed under and through Tucson Electric Power Company's (TEP) 345 kV right of way (ROW) in the Apache National Forest in NW New Mexico on the afternoon of June 14, 2000. At 1545 PDT, system protection opened the two 345 kV lines. To maintain system security, TEP initiated a rotating load shedding scheme using 30-minute increments. After about one hour, one of the 345 kV lines was restored to service, and the load shedding was cancelled.	N	Y		Y	102
6/28/2000 17:52	1.4	Virginia Power/North Carolina	SERC-VACAR	Y	Y	N	INT	30,500	175	Weather	System protection opened a 230 kV line on June 28 when a tree fell on. Later in the day, at about 1752 EDT, lightning struck a switch on a second 230 kV line, causing an outage to the line and a fire on the switch. This double contingency outage removed both 230 kV lines, leaving only a single 115 kV line to supply electricity to the area. The area demand exceeded the capacity of the 115 kV line, resulting in a voltage collapse and loss of service to the area. One of the two 230 kV lines was restored to service at 1855 EDT and service to the area was restored at 1912 EDT.	Y	Y		Y	160
6/29/2000 20:44	3.0	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	INT	1	1,630	Equipment malfunction	System protection opened Pole 1 and Pole 2 at Radisson at 20:44 EDT, interrupting the Radisson – Sandy HVDC line. The disturbance interrupted 1,630 MW of interruptible capacity. An investigation is underway.	Y	Y		Y	3,240
7/3/2000 5:20	1.3	Alaska Electric Light & Power	ASCC	Y	N	N	INT	14,273	35	Line fault	A B-phase to ground fault occurred on a primary transmission line, causing an area-wide interruption of service on July 3, 2000, at 0520 AST. The fault was cleared and service restored by 0637 AST. The cause of the fault was undetermined.	Y	Y		Y	30

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
7/5/2000 4:08	0.8	British Columbia Hydro & Power Authority	WECC-NWPP	N	N	N	INT	N/A	325	Unknown	One of B.C. Hydro & Power Authority's (BCH&PA) 500 kV Williston buses was isolated for maintenance work. This work required some 500 kV and 230 kV circuit breakers to be out of service, isolating two 500/230 kV transformers. At 0408 PDT, transformer protection for an unknown reason removed from service two parallel transformers on a second 500 kV bus. This action opened numerous 500 kV and 230 kV breakers and removed from service the parallel 500 kV bus, the 230 kV bus and the supply to a 60 kV bus. The de-energizing of the second 500 kV bus resulted in system protection removing a 500 kV line islanding a portion of the B.C. Hydro & Power Authority system. A large industrial customer remained connected to the islanded area and increased the amount of electricity it exported to the area from 35 MW to 130 MW. The islanded system frequency dropped to 58.8 Hz, and the WSCC Interconnection frequency increased to 60.041 Hz. When the 500 kV line was re-energized at 0453 PDT, BCH&PA resynchronized to the islanded area.	Y	Y		Y	163
7/10/2000 4:58	0.0	Hydro-Quebec TransEnergie	WECC-NWPP	Y	N	N	UO	0	N/A	Weather - lightning	Two lightning strikes within seconds of each other caused system protection to open four 120 kV lines on July 10, 2000, at 0438 EDT. Line flows on the system interrupted were a 400 MW import and an 800 MW export. Electric service to customers was not affected, however, system protection removed from service 17 generating units. The lines were restored to service immediately, and all generating units were back on line by 0500 EDT.	N	N	No FIRM demand interruption reported	Y	
7/13/2000 14:42	5.3	Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	UO	0	N/A	Equipment failure and weather - lightning	A 230 kV line was the only tie between Ontario and Manitoba on July 13, 2000. A second 230 kV tie between Ontario and Manitoba was out of service at the time. At 1442 EDT, the line that was in service was taken out of service due to a failed strain insulator. This action resulted in an Ontario/Manitoba separation. Service to customers was not affected, nor was any generation lost. The line that had been in service earlier in the day was returned to service at 1957 EDT. At 1616 EDT that same day, system protection opened two 230 kV circuits and one 115 kV circuit due to lightning. This action left the Ontario West system interconnected with the Minnesota system by one 115 kV line. The remaining line capacity was sufficient to maintain synchronism with the MAPP–US system and service to customers was not affected. Post contigency frequency in the Ontario West, East and the Minnesota systems remained at 60 Hz. The Ontario East and West systems were paralleled at 1640 EDT.	N	N	No FIRM demand interruption reported	Y	
7/17/2000 18:31	0.1	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Weather - lightning	Lightning strikes resulted in system protection to remove two 315 kV lines from service, resulting in a reduction of 200 MW in export power and the removal from service of ten generating units at La Grande on July 17, 2000, at 1831 EDT. Service to customers was not affected. The lines were restored immediately and all generating units were back on line by 1836 EDT.	N	N	No FIRM demand interruption reported	Y	
7/20/2000 13:56	N/A	Alabama Power Company	SERC-Southern	Y	N	N	INT	160,000	N/A	Weather	High winds and thunderstorms across central Alabama interrupted electric service to about 160,000 customers on July 20, beginning at 1800 CDT.	N	Y		Y	
8/4/2000 13:56	0.4	Power Pool of Alberta	WECC-NWPP	N	N	N	INT	N/A	190	Weather - lightning	The 500 kV tie between Alberta and B.C. Hydro & Power Authority (BC Hydro) was struck by lighting on August 4, 2000 at about 1356 MDT, causing system protection to open and lockout all three phases. System protection also removed two BC Hydro generating units from service. The remaining Alberta – BC Hydro ties opened on overload. As the frequency in the Alberta island dropped, 70 MW of firm demand and 120 MW of interruptible demand was shed by under-frequency relaying. Firm customer demand was restored at 1407 MDT and interruptible demand at 1420 MDT. Generation was restored by 2015 MDT.	Y	Y		Y	51
8/6/2000 16:00	32.0	Commonwealth Edison	MAIN	Y	Y	Y	INT	230,000	N/A	Severe weather	Severe weather conditions in the ComEd service territory interrupted electric service to more than 230,000 customers, beginning at about 1600 CDT on 08/06/00. Electric service to all customers was restored by 2400 CDT on 08/07/00.	N	Y		Y	
8/9/2000 18:30	29.5	Cinergy	ECAR	Y	Y	Y	INT	92,000	N/A	Severe weather	Major thunderstorms, accompanied by high winds, moved through the Cinergy service territory, beginning at about 1830 EDT on August 9, 2000. At the peak of the storm, 92,000 customers were without electric service in the southwest Ohio and Northern Kentucky portions of Cinergy's service territory. Electric service to all customers was restored by 2359 EDT on August 11.	N	Y		Y	
8/10/2000 21:30	20.5	Alabama Power Company	SERC-Southern	Y	N	N	INT	75,000	N/A	Severe weather	Major thunderstorms, accompanied by high winds, moved through the Alabama Power Company service territory, beginning at about 2130 EDT on August 10, 2000. At the peak of the storm, 75,000 customers were without electric service. Service to all customers was restored by 1800 CDT on August 11.	N	Y		Y	
8/18/2000 18:00	78.0	Duke Power Company	SERC-VACAR	Y	N	N	INT	130,000	500	Severe weather	Major thunderstorms, accompanied by high winds, moved through the Duke Power service territory, beginning at about 1800 EDT on August 18, 2000. At the peak of the storm, 130,000 customers were without electric service. Service to all customers was restored by 2400 EDT on August 21.	Y	Y		Y	26,124
8/22/2000 8:33	0.4	Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	INT	1	130	Severe weather	Lightning strikes caused system protection to open a 500 kV circuit and a 115 kV circuit on August 22, 2000, at about 0833 EDT, creating an electrical island in the northwestern part of Ontario, Canada. Two independent power producers (IPP) were removed from service as part of an automatic protection scheme. System protection at five additional IPPs removed from service a total of 140 MW. In addition, system protection at a large industrial customer opened a 230 kV breaker resulting in a 130 MW loss of demand. At 0854 EDT, the island was resynchronized and electric service restored to all customers.	Y	Y		Y	30

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
8/28/2000 12:00	8.0	Southern Indiana Gas & Electric Co.	ECAR	Y	Y	Y	PA	124,000	15	Inadequate generating reserves	A combination of high system demands and equipment outages resulted in inadequate generating reserves on the Southern Indiana Gas & Electric system on August 28, 2000. At 1200 CDT, interruptible customers (totaling 10-15 MW) were curtailed and a public appeal made for voluntary demand reduction. By 2000 CDT, the system demand decreased to the point where the public appeal was cancelled and interruptible customer demand was restored.	N	N	Public Appeal	Y	60
8/31/2000 13:39	N/A	Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	VR	N/A	N/A	Equipment malfunction	Turbine protection automatically removed Lennox G3 from service at 13:39 EST. At 13:40, Lennox G4 had a run back when protection removed a boiler from service. A 3% voltage reduction was implemented as a control action for the area control error.	N	N	Voltage reduction	Y	
9/1/2000 6:38	N/A	Georgia Power Company	SERC-Southern	Y	N	N	UO	N/A	N/A	Lightning	Beginning at 0637:54 CDT, three lightning strokes occurred in the immediate proximity of Plant Bowen. Equipment protection removed, nearly simultaneously, three of the four units from service. There was no coincident fault activity on the transmission system. No customer demand was interrupted during the event. A detailed investigation is underway to determine cause and remediation.	N	N	No FIRM demand interruption reported	Y	
9/17/2000	36.0	Florida Power Company	FRCC	Y	N	N	INT	120,000	N/A	Weather - Hurricane Gordon	Hurricane Gordon impacted Florida Power & Light's service territory on September 17-18, 2000, interrupting service to 120,00 customers at the height of the storm. Essentially all damage was confined to the distribution system. Service was restored to all customers by mid- morning on September 18.	N	Y		Y	
9/19/2000 20:25	0.1	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Human error	A maintenance work error at the Lemoyne substation caused equipment protection to remove three units at the La Grande 4 substation. The generation rejection worked correctly.	N	N	No FIRM demand interruption reported	Y	
9/28/2000 8:45	0.0	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Human error	Maintenance work at La Vérendrye station caused generation rejection at La Grande 2 station resulting in the shedding of generation for three minutes.	N	N	No FIRM demand interruption reported	Y	
10/8/2000 16:00	2.3	Commonwealth Edison	MAIN	Y	Y	Y	INT	11,000	N/A	Equipment failure	A 138 kV oil-filled circuit breaker at a ComEd substation exploded, showering debris and oil over adjacent equipment on October 8, 2000 at 1600 CDT. The debris caused short circuits and the oil ignited, resulting in a shutdown of the 138 kV, 69 kV, and 12 kV busses at the station. Service was interrupted to 11,000 customers,. Service was restored by 1815 CDT. The cause of the explosion is unknown, and is being investigated by ComEd and the equipment manufacturers.	N	N	No FIRM demand interruption reported	Y	
10/29/2000 18:50	0.1	Manitoba Hydro	MAPP-Canada	Y	Y	Y	UO	0	N/A	Equipment failure	The Manitoba Hydro HVDC reduction scheme operated due to a component failure in the static voltage compensator (SVC) controller on Sunday, October 29, 2000 at 18:50 CST. This component failure simulated the loss of the SVC and initiated the HVDC reduction. The amount of HVDC reduction was correct for the line loading. System protection did not remove any generation from service. The HVDC reduction was reset at 18:53 and HVDC loading was resumed.	N	N	No FIRM demand interruption reported	Y	
10/31/2000 18:29	8.2	Nebraska Public Power District	MAPP	Y	Y	Y	UO	0	N/A	Weather	System protection removed a 345 kV line due to a storm damage on October 31, 2000 at 1829 CST. At 1832, a second 345 kV line opened due to damage from the same storm system. A large generating unit was not in service due to maintenance and the several 230 kV lines were out of service for planned maintenance. With all of these lines out of service, there were no steady-state overloads, but NPPD was in an unstudied condition for transient stability. The 230 kV lines were returned to service by 2:43 a.m. on November 1. This condition has since been studied and NPPD is within stability limits.	N	N	No FIRM demand interruption reported	Y	
11/2/2000 2:23	0.0	Southern California Edison	WECC-CAMX	Y	Y	N	INT	N/A	160	Fire	System protection removed from service a Southern California Edison Company transformer bank, which faulted due to sudden pressure and immediately caught on fire on November 2, 2000 at about 0223 PST. As a result of the heavy smoke and flames, system protection removed from service the substation facilities affected. Due to the loss of a lower-voltage system at the substation, about 160 MW of customer demand was interrupted. The demand was restored about two minutes later when the SCE dispatcher transferred that demand to another low-voltage system.	Y	Y		Y	4
12/7/2000 17:15	2.3	California Independent System Operator	WECC-CAMX	Y	Y	N	DR	N/A	1,500	Inadequate generation resources	The California Independent System Operator declared a Stage 3 Emergency to be in effect on December 7, 2000, at 1715 PST. During the period from 1715 to 1930, about 200 MW of firm demand (California Dept. of water Resources pumping load) was interrupted. About 1,350 MW of interruptible demand was interrupted between 1610 and 2030. Public appeals for conservation were made throughout the day. The Stage 3 Emergency was cancelled at 1930 PST.	N	N	Capacity Issue	Y	2,261
12/13/2000	168.0	Southwest Power Pool	SPP	Y	Y	N	INT	235,000	1,400	Weather - ice storm	An ice storm caused major damage to transmission and distribution circuits in northeastern Texas and northeastern Louisiana on December 13, 2000. Service to 235,000 customers was interrupted and restoration was not completed until December 20.	Y	Y		N	157,584
12/16/2000 11:36	12.4	Alabama Power Company	SERC-Southern	Y	N	N	INT	50,000	N/A	Weather - tornado	A tornado swept through southeast Alabama damaging transmission and distribution lines on the morning of December 16, 2000. At the height of the storm, 50,000 customers were without electric service. Service to transmission customers was restored by midnight December 16. Electric service to distribution customers was restored on December 18 by 1800.	N	Y		Y	

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12/20/2000 2:31	15.0	New Brunswick Power Corp.	NPCC-Maritimes	Y	Y	N	INT	N/A	530	Weather - ice storm	Early on Monday, December 18, 2000 a storm struck southern New Brunswick (NB) with strong on-shore winds (up to 70 mph) all day, depositing salt contamination from high waves on the Bay of Fundy onto transmission apparatus in the Saint John area. Early on December 20, another storm moved in with light snow and rain, causing tracking of the contaminated insulators in the Saint John area and depositing freezing rain on the Moncton area transmission system. Saint John area transmission lines removed from service by system protection as a result of faults included: 345 kV, 138 kV, and 69 kV. Later in the morning, system protection removed from service transmission in the Moncton area due to freezing rain. A 138 kV fault on one of the lines to Prince Edward Island (PEI) caused the second line to open as well. One 345 kV line faulted and reclosed successfully and a transformer was removed from service at Salisbury due to a separate problem. Two other 345 kV lines had permanent faults, and the circuit breaker combination at Salisbury resulted in the opening of a fourth 345 kV line. As a result of loss of the three 345 kV supplies to the Moncton area, a local under-voltage load-shedding scheme operated. The faults are all believed to have been the result of sagging ice-coated overhead ground wires. All lines were returned to service later in the day after the ice fell off Investigation is on going into the performance of synthetic insulators during the salt/freezing rain conditions experienced in the Moncton area.	Y	Y		Y	5,309
12/25/2000 0:00	336.0	Southwest Power Pool	SPP	Y	Y	N	INT	94,285	460	Weather - ice storm	An ice storm caused major damage to transmission and distribution circuits in southwestern Arkansas, northeastern Texas, southeastern Oklahoma, and northwestern Louisiana on December 25, 2000. Service to over 94,000 customers was interrupted, and restoration was not completed until January 8, 2001. A total of 52 transmission lines (345 kV, 138 kV, and 69 kV) were out of service at the height of the storm.	Y	Y		N	103,555
1/3/2001 22:04	0.4	Hydro-Quebec	NPCC-HQ	N	Y	N	INT	71,000	450	Switching error	A switching error at the De Lery substation at 2204 on Wednesday, January 3 resulted in system protection removing a transformer from service and the opening of a 315 kV circuit between De Lery and another substation. Simultaneously, another 315 kV circuit, also between these same substations, opened due to a protection system failure. A total of 450 MW of customer demand was interrupted. Restoration of all customer demand was completed by 2230 EST.	Y	Y		Y	131
1/16/2001 0:00	18.0	California Independent System Operator (ISO) and various California Utilities	WECC-CAMX	Y	Y	N	INT	N/A	1,146	Insufficient generation	During the period January 16-21, 2001, the California ISO declared Stage 3 Emergencies which required the interruption of firm and interruptible demand in varying amounts and to varying numbers of customers in California on the following days: January 16, 2001 – 905 MW of California Dept. of Water Resources (CDWR) pumping demand interrupted between 0600 and 0700 hours and 643 MW of CDWR demand between 0700 and 1000 hours. Between 0600 and 1400 hours, between 288 and 1,146 MW of interruptible demand was curtailed and between 1600 and 2400 hours, between 3 and 1,095 MW of interruptible demand was curtailed. January 17, 2001 – 500 MW of firm customer demand was interrupted between 1100 and 1400 hours. Between 0500 and 2400 hours, between 292 and 841 MW of interruptible demand was curtailed. January 18, 2001 – 1,000 MW of firm customer demand was interrupted between 0900 and 1000 hours and 500 MW of firm customer demand was interrupted between 1000 and 1200 hours. 307 MW of California Dept. of Water Resources (CDWR) pumping demand interrupted between 0600 and 1200 hours. January 21, 2001 – 101 MW of firm customer demand was interrupted between 1400 and 1500 hours and between 1300 and 2000 hours, 234 MW of interruptible demand was curtailed.	N	N	Capacity Issue	Y	13,808
1/16/2001 22:38	2.6	British Columbia Hydro & Power Authority (BCHA)	WECC-NWPP	N	N	N	INT	100,000	430	Equipment failure	At about 2238 PST, on January 16, 2001, During a routine switching procedure at the Horne Payne 230 kV substation, the line side disconnects failed. When the 230 kV line circuit breaker was energized, a phase-to-ground fault occurred and system protection opened all 230 kV lines at the station. Service to about 100,000 electricity customers was interrupted. Restoration began at 2258 PST on January 16 and was completed by about 0114 PST on January 17.	Y	Y		Y	749
1/17/2001 5:00	19.0	California Independent System Operator (ISO) and various California Utilities	WECC-CAMX	Y	Y	N	INT	N/A	841	Insufficient generation	Continuation of CAISO incident of January 16, 2001.	N	N	Capacity Issue	Y	10,697
1/17/2001 17:57	2.3	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	INT	234,000	N/A	Equipment failure	A 735 kV circuit breaker at the Tilly substation exploded at 1757 EST, on January 17, 2001. System protection opened 735 kV circuits between the Tilly and Lemoyne substations. This, in turn, caused system protection to disconnect generators at three other power stations. System frequency declined, and under-frequency protection systems automatically	N	N	No FIRM demand interruption reported	Y	

The Improved Reliability benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

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1/18/2001 9:00	3.0	California Independent System Operator (ISO) and various California Utilities	WECC-CAMX	Y	Y	N	INT	N/A	1,000	Insufficient generation	Continuation of CAISO incident of January 16, 2001.	N	N	Capacity Issue	Y	2,010
1/21/2001 13:00	9.0	California Independent System Operator (ISO) and various California Utilities	WECC-CAMX	Y	Y	N	INT	N/A	101	Insufficient generation	Continuation of CAISO incident of January 16, 2001.	N	N	Capacity Issue	Y	609
1/22/2001 7:48	1.8	Consolidated Edison Company of New York, Inc.	NPCC	Y	Y	N	UO	0	N/A	Fire	A fire at a New York Power Authority facility on January 22, 2001 resulted in system protection removing four 345 kV and four 138 kV feeders to Manhattan. This created a situation in which the next contingency would require possible load shedding in networks in Manhattan. The New York Independent System Operator declared a Major Emergency at 0748 EST and Consolidated Edison Company (Con Edison) declared a Condition Yellow at 0825 EST. Two 138 kV feeders were restored by 0926 EST, at which time Con Edison terminate the Condition Yellow. The NYISO terminated the Major Emergency at 0934 EST.	N	N	No FIRM demand interruption reported	Y	
1/31/2001 9:13	0.2	El Paso Electric Company	WECC-AZNMSNV	Y	N	N	INT	N/A	116	Transmission line fault	A disturbance occurred on the EPE system at about 0913 MST on January 31, 2001. A jumper burned off on a 115 kV line causing an intermittent fault that lasted about 40 cycles. Arcing to this jumper caused the intermittent fault. This line and a 345 kV lines opened at about the same time. System protection removed the 345 kV line from service due to a communications channel problem. The fault spread to a second 115 kV line, which is under-built on the same structures, and system protection then removed the line from service. Because an autotransformer at the345 kV substation was not in service, a second 345 kV line also was removed from service. When the first 345k V line was removed from service, the entire fault contribution from the 345 kV system went through a third 345 kV line. This line had a hybrid POTT (Permissive Over-reaching Transfer Trip) scheme that was part of a voting scheme. Because the fault was so far from this line, the blocking part of the hybrid scheme did not identify the fault correct1y and system protection on the third 345 kV line operated independently, opening the line. This hybrid scheme has since been replaced by a standard POTT scheme. Due to the loss of these lines, the power flow on the remaining EPE 115 kV transmission system increased, resulting in voltage swings and decreased voltage on the system. The EPE under voltage protection scheme worked as designed and automatically disconnected 116 MW of customer demand at substations at various predetermined locations throughout the EPE system. The reduction in customer demand immediately stabilized the voltage swings and eliminated the low voltage condition. EPE restored all transmission lines to service by 0921 MST with the exception of the second 345 kV line. It restored electric service to all customers by 0924 MST. The second 345 kV line was returned to service at 1237 MST.	Y	Y		Y	14
2/10/2001 5:05	0.9	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	N/A	N/A	Equipment failure	The Phase II HVDC interconnection between Québec and New England was disconnected by system protection while delivering electricity to New England at 0505 EST on February 10, 2001. Generation in Québec was removed from service to compensate for the loss of the interconnection. Following reconnection, power delivery was resumed by 0602 EST from an alternate source..	N	N	No FIRM demand interruption reported	Y	
2/16/2001 15:15	N/A	Alabama Power Company	SERC	Y	N	N	INT	300,000	N/A	Weather - severe	Severe weather moved through Western Alabama with damaging winds on the afternoon of February 16, 2001,. Damage was reported in the Tuscaloosa area of Western Alabama and in Jefferson County. Several transmission lines were damaged and removed from service by system protection. Over 300,000 customers were without electricity at the height of the storm.	N	N	No FIRM demand interruption reported	Y	
2/28/2001 10:55	25.1	Various Pacific Northwest Region Companies	WECC-NWPP	Y	N	N	INT	258,000	1,340	Earthquake	This event involved various Pacific Northwest Region companies. — An earthquake registering 7 on the Richter Scale occurred about seven miles north of Olympia, Washington at about 1055 PST, on February 28, 2001. As a result of the earthquake, several 500 kV, 230 kV, and 115 kV transmission circuits were removed from service by system protection in the Northwest Region. During the event, system frequency ranged from 59.99 to 60.065 Hz. Western Systems Coordinating Council members reported about 1,340 MW of customer demand and about 258,000 customers were interrupted due to the event. Electric service was restored to essentially all customers by early in the morning of March 1, 2001.	Y	Y		Y	22,520

MidwestISO
Energizing the Heartland

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3/6/2001 9:17	N/A	Independent System Operator - New England	NPCC	Y	Y	N	INT	130,000	340	Weather - severe storm	A blizzard (Emily), accompanied by icing conditions, struck the Boston and Northeast Massachusetts area on the morning of March 6, 2001. By 0917 EST, two – 345 kV, three – 230 kV, and eight – 115 kV transmission lines were reported out of service. Broken static wires due to wind and icing on a 345 kV circuit and 115 kV circuit initially caused system protection to remove those two lines from service. Malfunctions in system protection and equipment failure in response to these incidents accounted for the remainder of the outages.	N	Y		Y	
3/10/2001 17:35	2.3	SaskPower	MAPP	N	N	N	INT	246,000	1,250	Equipment problems	System protection removed Poplar River station unit No. 1 from service due to turbine vibration at 1735 CST on March 10, 2001. About 1.5 minutes later, system protection removed Poplar River unit No. 2 and Boundary Dam unit No. 4 from service. No cause was indicated for these last two removals. The loss of generation in the SaskPower control area resulted in the overload and removal from service by system protection of all synchronous interconnections with MAPP. Because SaskPower was immediately deficient in generation, frequency dropped to about 58.05 Hz. This loss of generation resulted in the operation of all five stages of under-frequency demand reduction. Subsequent power and voltage swings resulted in the removal by system protection of additional generating capacity. SaskPower was resynchronized with MAPP at 1755 CST when one interconnection was restored. The remaining interconnections were restored by 1947 CST. Service to all customers was restored by 1950 CST.	Y	Y		Y	1,884
3/14/2001 12:30	26.5	Reliant Energy/HL&P	ERCOT	Y	Y	N	INT	114,000	N/A	Weather - severe	A strong line of thunderstorms entered the Reliant Energy HL&P service area bringing heavy rain, hail and high winds at about 1230 CST on March 14 2001. At the peak of the storm, an estimated 114,000 customers were without electric service. An estimated 223 circuits were affected by the storm. Service to all customers was restored by 1500 CST on March 15, 2001.	N	Y		Y	
3/19/2001 9:00	11.0	California Independent System Operator (ISO)	WECC-CAMX	Y	Y	N	INT	N/A	1,000	Insufficient generation	During the period March 19-20, 2001, the California ISO declared Stage 3 Emergencies which required the interruption of firm and interruptible demand in varying amounts and to varying numbers of customers in California on the following days: March 19, 2001 – between 401 and 1,000 MW of firm customer demand was interrupted between 1100 and 1700 hours. Between 0900 and 2000 hours, between 185 and 246 MW of interruptible demand was curtailed. March 20, 2001 – between 300 and 500 MW of firm customer demand was interrupted between 0900 and 1500 hours. Between 0800 and 2000 hours, between 72 and 189 MW of interruptible demand was curtailed.	N	N	Capacity Issue	Y	7,370
3/20/2001 8:00	12.0	California Independent System Operator (ISO)	WECC-CAMX	Y	Y	N	INT	N/A	500	Insufficient generation	Continuation of CAISO incident of March 19, 2001.	N	N	Capacity Issue	Y	4,020
4/4/2001 10:46	N/A	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Maintenance Error	During system protection maintenance at the Montagnais substation at 1046 EDT on April 4, 2001, three generating units at the Churchill Falls station were inadvertently removed from service, resulting in a loss of generation. No customers were affected.	N	N	No FIRM demand interruption reported	Y	
4/6/2001 6:43	3.2	Tacoma Power System	WECC-NWPP	Y	N	N	INT	120,000	600	Insulator failure	A system protection bus differential relay at the Cowlitz substation operated and removed from service all transmission lines in and out of the Cowlitz 230 kV main bus at about 0643 PDT on April 6, 2001. As a result, about 600 MW of customer demand was interrupted and 120,000 customers affected. With the loss of the bus, the north and west portions of Tacoma's service territory had insufficient generation to support demand. This disturbance resulted in significant under-voltage conditions and over loading of cross town subtransmission lines. About 33 MW of generation was removed from service by system protection in an effort to correct the situation. The cause of the initial bus differential relay operation is unknown at this time. Service to all customers was restored by 0958 PDT.	Y	Y		Y	1,300
4/12/2001 13:31	0.0	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Operator error	The inadvertent bypassing of series compensation equipment at 1331 EDT on April 12, 2001, at the La Verendry substation caused system protection to remove from service three generating units. No customers were affected. All three units were back in service by 1334 EDT. Also see the July 22, 2001 disturbance.	N	N	No FIRM demand interruption reported	Y	

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5/7/2001 10:00	8.0	California Independent System Operator (ISO)	WECC-CAMX	Y	Y	N	INT	N/A	300	Insufficient generation	During the period May 7-8, 2001, the California ISO declared Stage 3 Emergencies which required the interruption of firm and interruptible demand in varying amounts and to varying numbers of customers in California on the following days: May 7, 2001 – 300 MW of firm customer demand was interrupted between 1600 and 1800 hours and 300 MW of California Dept. of Water Resources (CDWR) pumping demand was interrupted between 1000 and 1300 hours and between 1600 and 1900 hours. Between 1000 and 1700 hours, 863 MW of interruptible demand was curtailed. May 8, 2001 – 400 MW of firm customer demand was interrupted between 1500 and 1700 hours and 300 MW of California Dept. of Water Resources (CDWR) pumping demand was interrupted between 1100 and 1500 hours. Between 1200 and 1900 hours, between 536 and 936 MW of interruptible demand was curtailed.	N	N	Capacity Issue	Y	1,608
5/8/2001 11:00	8.0	California Independent System Operator (ISO)	WECC-CAMX	Y	Y	N	INT	N/A	400	Insufficient generation	Continuation of CAISO incident of May 7, 2001.	N	N	Capacity Issue	Y	2,144
5/14/2001 7:07	N/A	Excel Energy	MAPP	Y	Y	Y	UO	0	N/A	Equipment malfunction	The transmission line connecting the Allen S. King plant with the Eau Claire substation was removed from service by system protection at 0707 CDT on May 14, 2001, due to a mechanical failure of a circuit breaker at the Eau Claire substation. System protection also removed from service the transmission line between the Eau Claire and Arpin substations. Incorrect settings on the newly installed system protection scheme took the King – Eau Claire line out of service two more times during the morning of May 14 (1129 and 1145 CDT) before the problem was corrected. No customers were affected.	N	N	No FIRM demand interruption reported	Y	
6/1/2001 13:30	N/A	Independent System Operator - New England	NPCC	Y	Y	N	UO	0	N/A	Equipment failure	An explosion and subsequent fire in a current transformer at the Maine Yankee station at 1330 EDT on June 1, 2001, caused system protection to remove from service the transmission line between Marcy and Maine Yankee stations. The loss of this line flow activated the New England Special Protection Systems (SPS) resulting in the "islanding" of Bangor, Maine and the Maritimes. The SPS also removed from service generating units at two other stations. When the islanding occurred, the frequency in the island rose, and special protection systems acted to reduced New Brunswick generation within the island. Frequency stabilized at 59.8 Hz about six seconds after the initial transmission line was removed from service. The Maritimes/Bangor "island" was re-synchronized to New England via a 115 kV circuit at 1608 EDT. No customers were affected by this incident.	N	N	No FIRM demand interruption reported	Y	
6/6/2001 16:22	2.8	American Electric Power - Central Power & Light Company	ERCOT	Y	Y	N	INT	24,506	350	Contractor accident	A construction crane contacted the Hidalgo Energy Center – Pharr Magic Coop line at 1622:56 hours causing the loss of about 35 MW of demand at the South East Edinburg station, which is tapped off the line. An additional firm demand loss of about 315 MW was due to under-voltage and over-current system protection opening numerous 12 kV feeder breakers.	Y	Y		Y	653
6/8/2001 20:00	169.0	Reliant Energy/HL&P	ERCOT	Y	Y	N	INT	36,073	N/A	Severe weather	Tropical Storm Allison made landfall between Galveston and Freeport, Texas on Tuesday, June 5, 2001. The entire Houston-Galveston Metro area experienced heavy rains, lightning, and some high wind. No excessive outages were experienced at this point. The weather system moved out of the Metro area on Wednesday and then returned beginning late Thursday. By Friday evening June 8, heavy rains settled in over the entire Metro area. Heavy flooding began to occur, and early on the June 9, the area was declared a major disaster. The flooding was the primary cause of outages, which left 36,073 customers without service.	N	Y		N	
6/11/2001 16:50	0.1	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	INT	N/A	620	Weather - lightning	A lightning strike caused system protection to remove from service the transmission line between Manic and Levis substations at 1650 EDT on June 11, 2001. A total of 620 MW of industrial demand was interrupted. Service was restored by 1657 EDT.	Y	Y		Y	48
6/18/2001 2:04	N/A	Excel Energy	MAPP	Y	Y	Y	INT	0	N/A	Equipment failure	A 3-phase bus potential transformer failed at the Edina substation at 0204 CDT on June 18, 2001. The resulting explosion and fire caused extensive damage to control cables and relaying in the substation control house, and prevented local system protection schemes from operating. The short circuit was eventually cleared after 14 cycles from adjacent substations.	N	N	No FIRM demand interruption reported	Y	
6/25/2001 14:25	32.2	Consolidated Edison Company of New York, Inc.	NPCC	Y	Y	N	UO	0	N/A	Loss of distribution network feeders	A "Condition Yellow" was declared at 1425 EDT in the Sheridan Square Network in Manhattan due to three of 12 feeders being out of service. The first feeder was taken out of service due to an emergency at 0524 EDT, the second feeder automatically disconnected at 1331 EDT, and the third feeder automatically disconnected at 1409 EDT. A worst case scenario would have resulted in loss of service to a hospital. One of the disconnected feeders was re-energized at 2239 EDT terminating the "Condition Yellow."	N	N	No FIRM demand interruption reported	Y	
6/27/2001 12:22	N/A	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Equipment failure	A short circuit occurred on a generator at the Churchill Falls station at 1222 EDT on June 27, 2001. System protection did not open the generator circuit breaker in the required time to isolate the generator, and the backup protection scheme disconnected the power transformer and the circuit breaker at a second generator. Other generators picked up the loss and no customers were affected.	N	N	No FIRM demand interruption reported	Y	

The Improved Reliability benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

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7/2/2001 16:03	0.7	Nevada Power Company	WECC-AZNMSNV	Y	N	N	DR	10,000	100	Insufficient generation	Extreme temperatures in the Nevada Power service area on July 2, 2001, resulted in a significant increase in customer demand. This increase, coupled with 402 MW of generation out of service, led to Nevada Power declaring a Condition Red at 1603 PDT and initiating its Emergency Demand Shedding Plan. About 10,000 customers on non-critical circuits were affected and 100 MW of demand was shed. At 1644 PDT, all customers were reconnected. Normal system operation was restored by 1800 PDT.	N	N	Capacity Issue	Y	46
7/8/2001 1:16	0.4	Independent Electricity Market Operator	NPCC	Y	Y	N	INT	160,000	500	Equipment failure	System protection removed two breakers from service at the Detweiler substation at 0116 EDT on July 8, 2001. This action resulted in the automatic removal from service of five transmission circuits terminating at the substation, a bus and an autotransformer. In addition, two other autotransformers and two other transmission circuits emanating from the Seaforth substation also were removed from service. The disturbance resulted in the instantaneous loss of about 500 MW, of which about 160 MW was a direct result of the substation configuration and about 340 MW by the disturbance itself. All demand was restored in about 22 minutes. During the equipment restoration, maintenance staff reported a loud noise coming from the insulators associated with the Detweiler bus and the bus was removed from service. When no reason could be found for the noise, it was restored to service. Three Detweiler breakers and a transmission circuit remained out of service at the time the disturbance report was prepared. The event was under investigation.	Y	Y		Y	123
7/13/2001 8:20	0.3	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Equipment failure	A fire on one phase of a 13.8/735 kV power transformer at the LaGrande 2P substation caused system protection to operate to isolate the transformer at 0820 EDT on July 13, 2001. In addition to isolating the transformer, system protection removed from service a high-voltage bus at the LG 2P substation and two generating units at the LaGrande 2C power station. The transmission line between Radisson and Nemiscau substations was also removed from service. No service to customers was affected. Frequency was restored at 0821:03 and voltage levels return to normal at 0831:08. The bus at LG 2P substation was back in service at 0835:14 EDT.	N	N	No FIRM demand interruption reported	Y	
7/21/2001 17:01	0.2	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Weather - lightning	A lightning strike on the transmission line between Montagnais and Churchill Falls stations caused system protection to remove the line from service at 1701 EDT on July 21, 2001. Also removed from service by the protection scheme were generating units at Churchill Falls station. Service to customers was not affected. The line reconnected automatically after five seconds, and the generators were restored to service by 1712 EDT.	N	N	No FIRM demand interruption reported	Y	
7/21/2001 20:07	0.8	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Weather - lightning	At 2007 EDT on July 21, lightning strikes on the transmission lines between Tilly and Nikamo substations caused system protection to remove transmission lines from service, and interrupted connections to several stations. The transmission lines were re-energized and all generators restored to service by 2057. Service to customers was not affected.	N	N	No FIRM demand interruption reported	Y	
7/21/2001 20:22	0.6	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Weather - lightning	Lightning strikes on the transmission lines between Tilly and Nikamo substations again caused system protection to remove transmission lines from service at 2022 EDT on July 21, and interrupted connections to two stations. The transmission lines were re-energized and generators restored to service by 2057 EDT. Service to customers was not affected.	N	N	No FIRM demand interruption reported	Y	
7/22/2001 16:01	1.3	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Weather - lightning	Lightning strikes on transmission lines caused system protection to remove several transmission lines from service at 1601 EDT on July 22, 2001, and interrupted connections to several stations. The transmission lines were re-energized, and all generators restored to service by 1719 EDT. Service to customers was not affected.	N	N	No FIRM demand interruption reported	Y	
7/22/2001 19:50	N/A	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Maintenance error	While maintenance on system protection relays was taking place at the Churchill Falls station, the system protection system was inadvertently activated at 1950 EDT on July 22, 2001, and two generating units, were removed from service. The units were restored to service by 2011 EDT. Electric service to customers was not affected. Also see the HQ incident of April 12, 2001.	N	N	No FIRM demand interruption reported	Y	
7/24/2001 14:29	1.3	Hydro-Quebec/TransEnergie	NPCC-HQ	N	Y	N	INT	N/A	390	Weather - lightning	Lightning strikes on transmission lines between the Abitibi and Lebel substations caused system protection to remove the lines from service at 1429 EDT on July 24, 2001. Generation also was removed from service. A total of 390 MW of customer demand served from the Lebel substation was interrupted. Service to all customers was restored by 1546 EDT.	Y	Y		Y	335

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8/1/2001 5:37	7.8	Montana Power Company	WECC	Y	N	N	UO	0	N/A	Line fault	Because of the sensitivity of the information concerning this event, the names of the utilities, switchyards, and power plants involved have been removed. A 500 kV circuit breaker was out of service for scheduled maintenance at Switchyard B in the Western Systems Coordinating Council (WSCC) on August 1, 2001. To satisfy WSCC power-flow stability study concerns, the control area operator intentionally opened two additional 500 kV breakers per a modified operating procedure. Opening these two breakers, with the one breaker out of service, split the 500 kV east and west buses at Switchyard B. At about 0537, one of two 500 kV transmission lines from the west of Switchyard B faulted due to an animal (raptor) contact and was removed from service. The remaining in-service line breaker at Switchyard B properly opened single-pole and reclosed during the fault sequence. During this single pole opening operation, the transformer's sudden pressure relay operated and cleared the bus. One of the breakers that opened three-pole was the breaker that had just opened and reclosed single-pole on the transmission line from the west. Because of the substation configuration and the clearing of the transformer, a second transmission line from the east was open ended at Switchyard B. A special acceleration trend relay (ATR) scheme operated correctly for this fault and removed from service generating units at Station C to the east of Switchyard B Control area substation personnel were dispatched to the Switchyard B to inspect and test the transformer. Control area operators closed one of the breakers at Switchyard B that had been opened due to the breaker maintenance and restored the open-ended second transmission line from the east at 0719. The transformer and the bus remained de-energized. The first transmission line from the west was patrolled and released for service. At about 1306, the transformer was returned to service using one of the transmission lines from the east. Before control area operators could re-energized Switchyard B, a second disturbance occurred. At about 1318, a fault occurred on a second transmission line from the east. The line was inspected, and once again, the fault was animal contact (raptors). Because the first transmission line from the west had not yet been restored from the earlier event that day, the open-ending of the second line from the west at Switchyard B left Generating Station C to the east without a path to the west and its output was removed from service. Three adjacent control areas felt some effects with respect to voltage and frequency during both excursions, but no customer-demand was interrupted, or generation removed from service in	N	N	No FIRM demand interruption reported	Y	
8/7/2001 0:13	N/A	Manitoba Hydro	MAPP	Y	Y	Y	UO	0	N/A	Special protection system missoperation	The Dorsey HVDC Allocator Reduction scheme operated due to a false signal at 00:13 CDT on Tuesday, August 7, 2001. No breaker operations occurred at the substations involved that were coincident with this operation. It is suspected this false special protection system operation is due to a problem with the microwave tone equipment, and it is under further investigation. No generation was removed from service, but a false HVDC reduction was initiated. No transmission lines were removed from service. No customers were affected.	N	N	No FIRM demand interruption reported	Y	
8/9/2001 15:11	4.0	Electric utilities in the PJM Interconnection and Dominion - Virginia Power	MAAC	Y	Y	N	VR	600,000	1,000	Weather - heat wave, low voltage	PJM Interconnection, L.L.C. ordered a 5% voltage reduction on August 9 at 1440 EDT on the eastern portion of the PJM Interconnection and extended the voltage reduction to the entire PJM Interconnection at 1510 EDT. The voltage reduction was implemented across the PJM Interconnection because of high electrical demand due to the extremely hot weather along the East Coast. No PJM Interconnection customers lost of service due to the voltage reduction, although demand dropped by about 700 to 1,000 MW when the voltage reduction was initiated.	N	N	Voltage reduction	N	2,691
8/9/2001 15:11	4.0	Electric utilities in the PJM Interconnection and Dominion - Virginia Power	SERC	Y	N	N	VR	600,000	200	Weather - heat wave, low voltage	Dominion Virginia Power also implemented a 5% voltage reduction on August 9, 2001 between 1511 to 1912 hours EDT. The voltage reduction was necessary due to low voltages on the AP-VP-PJM (Allegheny Power–Virginia Power–PJM) interface and supported a voltage reduction initiated by PJM. The voltage reduction provided reactive support in managing Vary reserves due to the heavy demands from the extremely hot weather along the East Coast. No Dominion Virginia Power customers lost service (i.e. no blackouts) due to the voltage reduction, although demand dropped by about 200 MW when the voltage reduction was initiated. This demand gradually returned over the next half hour. About 600,000 customers in the Northern Virginia service area were affected by the voltage reduction.	N	N	Voltage reduction	N	538
8/20/2001 14:40	N/A	Consolidated Edison Company of New York, Inc.	NPCC	Y	Y	N	VR	0	N/A	Loss of distribution feeders	Consolidated Edison Company reported at 14:40 hours on Monday, August 20, 2001, a condition Red with a voltage reduction of 8% affecting nine networks in the Manhattan area. This condition was due to the loss of seven transmission feeders and overload of the remaining feeders.	N	N	Voltage reduction	Y	

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9/6/2001 3:35	N/A	Montana Power Company	WECC-RMPA	Y	N	N	UO	0	N/A	Line fault	At about 0335 MDT, system protection opened one of the Broadview–Garrison lines due to a fault. While testing this line, system protection opened one pole (cause unknown) on a second Broadview–Garrison line. It reclosed at about 0338. At the same time, system protection opened a third transmission line, (cause unknown; reclosed at 0345:35) and an acceleration trend relay (ATR) at a second substation removed from service generating units to stabilize the event. At 0339:75, protection removed hydro generation (55MW) from service (cause unknown); it was returned to service. One generating unit was returned to service on September 6. No other facilities were impacted. As a result of the event, no interruption to customer demand was reported	N	N	No FIRM demand interruption reported	Y	
9/11/2001 8:48	N/A	Consolidated Edison Company of New York, Inc.	NPCC	Y	Y	N	DR	12,000	190	Terrorist Act	Terrorist attacked both World Trade Center towers, and demand began to decrease. At 09:52 hour, the Trade Center network was lost, representing nine customers and about 50 to 60 MW of demand. At 1651 EDT, two networks were removed from service by Consolidated Edison Company due to the threat of collapse of World Trade Center Building Seven, situated directly above the two Trade Center stations feeding these networks. A total of 9,752 customers, or 67 MW of demand, was removed from service. At 1721, World Trade Center Building Seven collapsed and destroyed both of the World Trade Center stations. Two feeders supplying a third network also were damaged, resulting in the decrease of another 64 MW of demand (2,252 customers)	N	N	Terrorist Event	Y	
9/14/2001 4:00	N/A	Florida Power Corporation and Tampa Electric Company	FRCC	Y	N	N	INT	203,000	N/A	Weather - Hurricane Gabrielle	Tropical Storm Gabrielle moved through the Florida Power Corporation service area beginning at about 4:00 am on September 14, 2001. The storm made landfall on the west coast of Florida in the vicinity of Sarasota, Florida with 70 mph winds. The storm caused numerous distribution system outages with a maximum of 102,000 customers whose electric service was curtailed across the system. Pinellas County, which experienced the highest winds, had the largest number of customer outages – 69,000 customers. It is estimated that most of theses customers will have service restored within 24 hours. There were no generating units removed from service as a result of the storm. Tropical Storm Gabrielle also passed through the Tampa Electric Company service area the same day disrupting service to 101,204 customers. All customers were restored by 2:30 A.M. on September 17. Only one generator was removed from service due to storm related causes. It returned to service on September 16.	N	Y		Y	
9/18/2001 8:26	1.8	Burbank Public Service Department	WECC-CAMX	Y	N	N	INT	50,462	134	Equipment failure	The Burbank Public Service Department and Los Angeles Department of Water and Power (LADWP) systems were separated at about 826 PDT, when system protection removed from service a transformer bank at Toluca due to sudden pressure relay. Burbank was importing 124 MW at the time with a system demand of 134 MW. It reported 10 MW of internal generation was automatically removed from service as a result of the disturbance. At 0900 PDT, Burbank closed the emergency tie to Glendale to supply station service and start up power. Between 0903 and 1020, Burbank synchronized and place in service three generators. One generator had been automatically removed from service due to the disturbance. It was returned to service at 1442 PDT. No other facilities were impacted. At about 1011 PDT, the LADWP dispatchers notified Burbank it had inspected the transformer bank, reset the sudden pressure relay, and requested Burbank energize the bank. The two systems were paralleled at 1017 PDT. As a result of the event, 134 MW of customer demand and about 50,462 customers were interrupted. All customer demand was restored at 1055 PDT.	Y	Y		Y	166
9/24/2001 21:51	0.7	Modesto Irrigation District	WECC-CAMX	Y	N	N	INT	40,000	150	Weather - lightning	Prior to the September 24, 2001 outage, part of the Modesto Irrigation District (MID) system demand was being served from a transformer at Parker and the remainder of was being served from the City and County of San Francisco (CCSF) interconnection. A second transformer was not in service. At about 2151 PDT on September 24, a thunderstorm moved through the MID service territory. A lightening strike in close proximity to the MID Parker substation resulted in disconnecting the transformer bank. A MID generator was removed from service by system protection; it was returned to service at 2316 PDT. These events resulted in interruption of service to about 40,000 customers (150 MW); MID restored service to them by 2235 PDT. Prior to the outage on September 25, the MID system was interconnected to the Pacific Gas & Electric Company (PG&E)/CCSF systems via two transmission interties only, due to the September 24 outage. At about 0052 PDT on September 25, both ties with CCSF were removed from service by system protection due to severe thunderstorm activity and the MID system was islanded. Internal generation remained on line. Under-frequency relaying interrupted service to about 59,000 customers (138 MW); service was restored at 0130 PDT.	Y	Y		Y	74

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9/25/2001 0:52	0.6	Modesto Irrigation District	WECC-CAMX	Y	N	N	INT	59,000	138	Weather - lightning	Continuation of Modesto Irrigation District incident of September 24, 2001.	Y	Y		Y	59
9/25/2001 23:20	4.2	City of Homestead, FL	FRCC	Y	N	N	INT	15,000	49	Equipment failure	An oil circuit breaker at the Lucy substation exploded at about 2320 hours EDT. System protection opened breakers at the Lucy and McMinn substations, separating the City of Homestead from the Florida transmission system. The explosion was caused by an internal fault in the circuit breaker. All of Homestead's customers were affected. The City of Homestead implemented its "Black Start" procedure and restored service to its customers.	Y	Y		Y	137
10/2/2001 8:46	0.1	Potomac Electric Power Company	MAAC	Y	Y	N	INT	1,646	168	Unknown	Supply to two downtown substations in Washington DC was interrupted for four minutes causing an interruption of service to all customers supplied from these substations. Although service was restored to all customers within four minutes, service restoration to numerous customers took longer due to internal customer switching actions that were necessary. Service was interrupted to the FBI building, Justice Dept, numerous other governmental buildings, museums and monuments on the Mall, and numerous commercial customers. Initially, no specific equipment failure mode or personnel action was identified that would account for the disturbance, and the investigation is continuing.	Y	Y		Y	8
11/14/2001 6:35	5.2	American Transmission Company acting for Wisconsin Electric Power Co., Edison Sault Electric Co., Wisconsin PS Corp., and Upper Peninsula Power Co.	MAIN	Y	Y	Y	INT	N/A	263	Ground fault	Several transmission lines supply electricity from northeastern Wisconsin to the western and upper peninsula areas of Wisconsin. One transmission line was out of service for the addition of a new substation. A second line contacted a tree, and system protection removed it from service. A third circuit became overloaded, sagged into a distribution line under it, and was removed from service by system protection. The two other lines also were removed from service by system protection. Some factors affecting the outage: the distribution lines in question were recently rebuilt higher than they had been previously, there was no wind, and the transmission line sag design assumed a wind of 3 mph and a lower ambient temperature. System protection disconnected the transmission facilities islanding the western and upper peninsula areas and interrupting 263 MW of customer demand. Under-frequency system protection interrupted about half of the demand and customer system protection interrupted the other half. Most of the residential demand was restored within the hour; the industrial demand was restored within eight hours. The utility subsequently lowered the distribution lines to their previous height.	Y	Y		Y	910
11/24/2001 0:00	N/A	Pacific Gas & Electric Company	WECC-CAMX	Y	Y	N	INT	500,000	N/A	Weather - severe	A blast of winter weather chilled California on 24 November, toppling trees and knocking out power to many customers. By November 25, about 500,000 Pacific Gas and Electric Company customers, mostly in the northern part of the state, were without electricity. By the evening, crews had restored electricity to most of the affected customers, but electric service had not yet been restored to about 119,000 homes.	N	Y		Y	
12/11/2001 17:56	N/A	Florida Reliability Coordination Council for all FL utilities	FRCC	Y	N	N	INT	N/A	1,200	Missoperation of a special protection system	A software problem resulted in data intended for a new, off-line EMS database to be inadvertently written back to an on-line system on December 11, 2001 at 17:56 EST. This accidental rewrite resulted in the skewing of data to a computer program for a special protection system (SPS) known as FALS (Fast Acting Load Shedding) which caused the SPS to operate. The loss of the demand produced a frequency spike on the Eastern Interconnection to 60.04 Hz. Once it was recognizing that the system had operated incorrectly, dispatch personnel immediately began restoring demand. There were no consequential overloads or voltage problems, and the bulk system remained intact at all times. Steps were taken to prevent a recurrence of this type of event.	N	N	Restoration Time Unknown	Y	
1/30/2002 18:00	198.0	Oaklahoma Gas & Electric Co., Kansas City Light & Power Co. and Missouri Public Service Co.	SPP	Y	Y	N	INT	570,000	1,310	Weather - Ice storm	On January 29, 2002, a major winter storm with freezing rain and ice caused system-wide power outages to a large portion of the distribution systems in parts of Oklahoma, Kansas, and Missouri. Approximately 570,000 customers were affected by the storm, which continued through January 31, 2002. The storm caused numerous downed conductors and equipment damage. Some high voltage transmission facilities were also affected.	Y	Y		N	173,785
2/27/2002 10:07	0.6	NPCC-Ontario	Independent Electricity Market Operator	Y	Y	N	INT	N/A	319	Equipment failure	At 1007 on Wednesday February 27, 2002, a major generating station stopped generating electricity due to failure of the station instrument air supply. Total generation automatically shed was 1,881 MW. At the time, maintenance crews were conducting planned work planned on a station service bus, isolating air compressors. Problems were encountered required the work crew to expand the isolation zone, thereby removing an additional compressors from service. While switching the additional compressors out of service, another compressor was automatically removed from service causing an overload on the remaining air compressors and the complete loss of station instrument air. As a result of the loss of generation, the control area operator activated a reserve sharing plan and instituted a 3% voltage reduction, which resulted in an additional 319 MW of load relief.	Y	N	Voltage reduction	Y	118

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Midwest ISO
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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
2/27/2002 10:42	0.9	San Diego Gas & Electric Company	WECC-CAMX	Y	Y	N	DR	210,882	340	Human error	On February 27, 2002 at 1042 MST, during a routine work on a section of a high voltage transmission substation bus, a technician working on the breaker failure relay for a breaker on a bus accidentally initiated system protection, which it to remove from service a section of the bus. As a result of this incident, other system protection equipment removed from service about 1,100 MW of generation and de-energized several high voltage transmission lines, which depressed nearby voltages and over loaded an adjacent high voltage transmission line. The control area operator ordered San Diego Gas & Electric Company to shed about 340 MW of local customer demand to restore the voltage and return the overloaded transmission line within normal operating limits. By 1137 MST, the control area operator completed restoration of the transmission system and all customers had their electric service restored	N	Y		Y	209
2/28/2002 21:24	6.5	WECC-CAMX	California Independent System Operator	Y	Y	N	UO	0	850	Equipment failure	On February 28, 2002 at 2124 PST, system protection removed from service a high voltage transmission line due to high winds. Because of an earlier event that removed an adjacent high voltage transmission line from service, a special protection scheme activated. This action resulted in the removing from service a high voltage transformer, and two additional high voltage transmission lines. In addition, the special protection scheme sent signals to shed non-firm pump demands and inserted various capacitors to stabilize voltage in the area. By 0354 PST, the control area operator had restored most of the transmission system. The original faulted transmission lines remained out of service for repairs. The special protection scheme operated as designed. There was no generation or firm customer demands shed because of this disturbance.	Y	Y		Y	3,702
3/9/2002 12:00	60.0	ECAR	Consumers Energy Company	Y	Y	Y	INT	190,000	190	Weather - severe storm	On Saturday, March 9, 2002 at about 1200 hours EST, a cold front moved through the state of Michigan accompanied by high winds and heavy rain. Gusts up to 60 mph were reported. The winds subsided by Sunday afternoon. About 190,000 customers were left without electric service. Electric service was restored to all but 6,900 customers as of 0600 hours Monday. Electric service was expected to be restored to almost all but a few customers by 2400 hours on March 11, 2002. The majority of the damage sustained was in the distribution system and portions of the subtransmission system.	Y	Y		Y	7,636
3/9/2002 17:01	2.8	NPCC-Ontario	Independent Electricity Market Operator	Y	Y	N	INT	46,000	196	Weather - strong winds	At 1701 EST, system protection removed from service four high voltage transmission lines. Three of the affected transmission lines share a common right of way. One of the transmission lines was carry additional load because of a planned outage on a high voltage transformer. During the disturbance, service was interrupted to about 40,000 customers (196 MW). At about 1947 EST, system operators restored all customer demands and much of the affected transmission.	Y	Y		Y	363
3/20/2002 9:14	0.8	WECC-NWPP	Power Pool of Alberta	N	N	N	INT	17,000	274	Equipment failure	On March 20, 2002 at 0914 PST, a portion of a control area's transmission system, while operating with only one of its two high voltage transmission system tie lines in-service, became "islanded" and 274 MW of customer demand was curtailed. The disturbance was initiated by the loss of one of two boiler feed water lines at a 2 x 125 MW gas-fired station in the area. This disturbance resulted in the loss of generation at five gas-fired generators (totaling 390 MW) located at four different stations, during a 5 minute 20 second period. The resulting import electricity flow into the area, combined with the resulting insufficient local voltage support caused the remaining high voltage transmission system tie line to open. The one of the high voltage transmission system tie lines was re-energized within 17 minutes to allow generation and customer demand restoration efforts to begin. About 17,000 customers were without electricity for up to 45-minutes.	Y	Y		Y	150
3/21/2002 13:32	N/A	NPCC-Quebec	Hydro-Quebec TransEnergie	N	Y	N	UO	0	N/A	Human error	On March 21, 2002 at 1332 EST, system protection removed from service one of two high voltage transmission lines connecting two generating stations, when a technician mistakenly applied a ground wire to the wrong circuit during routine maintenance. System protection also sent a trip signal removing from service the remaining high voltage transmission line. A total of 730 MW of generation was removed from service upon the loss of the second transmission line. At 1421, all generation and transmission circuits were restored.	N	N	No FIRM demand interruption reported	Y	
3/25/2002 6:07	N/A	NPCC-Maritimes	New Brunswick Power Corpration	N	Y	N	UO	0	N/A	Logging activity	On March 25, 2002 at 0607 EST, system protection removed from service a high voltage transmission line between separate regions of the bulk power system. This loss resulted in the islanding of one region. As a result of the islanding, the region had a surplus of 407 MW of generation. The total customer demand in the islanded region helped limit the frequency rise, which was too slow to activate a special protection system (SPS). However, an SPS in Maine did finally remove from service some generation to stabilize the frequency in the islanded region. By 1200 EST, all generation and the transmission system was restored. Upon investigation, it was found that the cause of this disturbance was attributed to logging activity in the vicinity of the high voltage transmission lines.	N	N	No FIRM demand interruption reported	Y	

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4/17/2002 12:26	6.6	WECC-AZNMSNV	Arizona Public Service Company	Y	N	N	UO	0	N/A	Equipment failure	On April 17, 2002 at 1226 PDT, one of the high-voltage circuit breakers for a large generating unit failed. As a result, system protection removed from service one of the bus sections at the generating station, which at the time was supplying station service power to the emission abatement station service for another generating in an off-normal configuration. About 20 seconds later another large generating unit was removed from service due to boiler instability, which was attributed to the loss of the emission abatement station service. At 1256 PDT, a third large generating unit was removed from service because of high furnace pressure, which was attributed to the loss of instrument air to booster fans. At 1300 PDT, a fourth generating unit was removed from service manually due to temperature problems also associated with the loss of station services. About 1,885 MW of generation was removed from service. There were no customer demand or transmission lines lost as a result of this event.	N	N	No FIRM demand interruption reported	Y	
4/23/2002 15:50	4.2	ECAR	AEP and Indianapolis Power & Light Company	Y	Y	Y	INT	1	39	Equipment failure	On April 23, 2002 at 1550 EDT, system protection removed from service a high voltage transmission line during switching to restore a circuit breaker on this line. When the breaker was closed, a column/pole disagreement condition occurred. This condition was detected by pole disagreement relaying, and resulted in system protection removing from service another high voltage transmission line, which isolated the total generating stations power output onto a single high voltage transmission line. Oscillations immediately occurred on the two generating units. After about six seconds, system protection removed the remaining high voltage transmission line from service in response to the oscillations, and system protection removed from service the two large generating units due to over-frequency relaying. Also related to this event, system protection removed from service another generating unit about 12 seconds after the start of this event in an adjacent control area. The exact cause of this loss of generation has not been determined, but preliminary analysis indicates that a generator control problem occurred on the unit. The other units at this same generating station remained on line during the event.	Y	Y		Y	111
4/27/2002 20:44	N/A	MAPP-Canada	Manitoba Hydro Transmission Services	N	Y	Y	UO	0	N/A	Equipment failure	On April 27, 2002 at 2044 CDT, a high voltage dc transmission line power reduction scheme operated due to a false signal received from one of the dc terminals. The false signal indicated that system protection removed from service one of the high voltage ac transmission lines near one of the dc terminals. Upon investigation, it was found that one circuit breaker operations occurred and the false signal may have been due to a problem with microwave tone equipment.	N	N	No FIRM demand interruption reported	Y	
4/29/2002 16:21	7.6	FRCC	Jacksonville Electricity Authority	Y	N	N	INT	360,000	2,100	Equipment failure	On April 29, 2002 at 1621 EDT, system protection removed from service a high voltage transmission line due to a failure of a lightning arrester. In the process of clearing the fault, system protection also removed another high voltage transmission line, which caused a severe overload on an adjacent high voltage transmission line. This overload eventually caused system protection to remove the line from service. After the overloaded transmission line was removed from service, portions of the bulk transmission system feeding into the area became heavily loaded and system protection removed from service other transmission lines due to an out-of-step conditions. This action islanded the Jacksonvile Electric Authority. The resulting island was generation deficient and underfrequency protection shed about 1,950 MW of customer demand. In addition, another 150 MW of interruptible demand was shed during this event along with some local generation. About 360,000 customers were affected by this even	Y	Y		Y	10,740
5/13/2002 18:45	41.3	SERC-VACAR	Duke Energy Corporation	Y	N	N	INT	74,000	250	Severe thunderstorms	On May 13, 2002 at about 2300 EDT, About 74,000 customers were without power as a line of severe thunderstorms went through portions of North and South Carolina. The thunderstorms cased wide-spread customer outages mainly in the distribution system. Electric service to all customers was restored by 1200 EDT on May 15, 2002.	Y	Y		Y	6,909
6/6/2002 13:48	N/A	WECC-CAMX	California Independent System Operator	Y	Y	N	UO	0	N/A	Wild fires	At about 1348 PDT on June 6, 2002, system protection removed from service a high voltage dc transmission line. As a result, a special protection system (SPS) removed about 2,820 MW of generation from service to protect other elements of the bulk electric system. The cause of this event was due to heavy smoke from a wild fire burning near the dc transmission line. No customer demand was lost during this event.	N	N	No FIRM demand interruption reported	Y	
6/18/2002 1:30	1.8	WECC-NWPP	British Columbia Hydro Power Authority	N	N	N	INT	19,000	334	Weather - lightning	At about 0130 PDT on June 18, 2002, system protection removed from service a high voltage transmission line due to suspected lightning strikes. Because another high voltage transmission line was already out of service for scheduled maintenance, a portion of the control area's transmission system now was asynchronously connected to the rest of its transmission system and was generation deficient. Under-frequency protection shed about 189 MW of firm customer demand, which caused the frequency to increase about 60.00 Hz. This rise in frequency caused system protection to remove from service 140 MW of local generation, which caused the frequency to decline again. Under-frequency relaying shed about another 145 MW of firm customer demand. At 0316 PDT, system protection removed from service two merchant generating units due to over-frequency. About 19,000 customers were affected by this event.	Y	Y		Y	399

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6/26/2002 18:13	3.7	WECC-CAMX	California Independent System Operator	Y	Y	N	INT	460,000	1,450	Wild fires	At about 1755 PDT on June 26, 2002, system protection removed from service one of several high voltage transmission lines that was near a wild fire burning in the area of a major transmission corridor. Subsequently, system protection removed other transmission lines from service at various times. During the event, the system operators attempted to restore each transmission line after it was removed from service. At 1813 PDT, as a result of three concurrent transmission line outages, a special low voltage load shedding scheme operated shedding about 1,450 MW of firm customer demand and about 98 MW of small local generation by independent power producers. About 460,000 customers were affected by this event. By 1956, electric service to all customers was restored. Several of the transmission lines remained out of service for repair or insulator washing due to contamination from the heavy smoke in the area.	Y	Y		Y	3,611
7/3/2002 15:31	0.8	NPCC-Maritimes	New Brunswick Power Corporation	N	Y	N	INT	65,000	210	Ground fault & equipment failure	On July 3, 2002 at 1531 ADT, system protection, momentarily, removed from service a high voltage transmission line. A few cycles after reclosing, the fault reoccurred and system protection again removed from service this transmission line. Because of an apparent failure of the anti-pumping mechanism, the circuit breakers reclosed again into the fault. Because of the bus configuration at one terminal, system protection removed from service four other incoming high voltage transmission lines by breaker failure relay action. This caused interruptions to about 65,000 customers. By 1617, electric service to all customers was restored.	Y	Y		Y	108
7/9/2002 0:46	2.0	FRCC	Lake Worth Utilities	Y	N	N	INT	18,351	33	Weather - lightning & equipment failure	On July 9, 2002 at 0046 EDT, system protection removed from service a distribution transformer. As a result, electric service to 18,351 customers was interrupted. By 0249 EDT on July 10, 2002, electric service to all customers was restored.	Y	Y		Y	45
7/9/2002 9:56	1.7	FRCC	Lake Worth Utilities	Y	N	N	INT	25,000	48	Equipment failure	On July 11, 2002 at 0956 EDT, system protection removed from service a distribution feeder circuit due to a lightning arrester failure. Because the system was reconfigured after a disturbance earlier that day (see previous report) the lightning arrester failure resulted in severely overloading a second substation. System protection subsequently removed the second substation from service due to the overload, blacking out the city. About 25,000 customers were without electricity as a result of this event. By about 1141, electric service to all customers was restored.	Y	Y		Y	56
7/11/2002 16:00	N/A	NPCC-Ontario	Independent Electricity Market Operator	Y	Y	N	OSL	0	N/A	Ground fault	On July 11, 2002 at 1600 EDT, system protection removed from service one of two high voltage transmission lines as the system operator was attempting to restore the other high voltage transmission line, which had been removed from service earlier by system protection. This caused a system separation between two systems. There was no customer loads or generation lost during this event. This is an operating security limit violation.	N	N	No FIRM demand interruption reported	Y	
7/15/2002 18:35	0.1	FRCC	Lake Worth Utilities	Y	N	N	INT	25,000	83	Equipment failure	On July 15, 2002 at 1835 EDT, system protection removed from service a generating unit, which had recently been place back in service after being out of service since 1989 . The loss of generation caused an overload on a high voltage circuit breaker, which was then removed from service by system protection. Because the area was generation deficient, service to about 25,000 customers was interrupted. By 1952 EDT, electric service to all customers was restored.	Y	Y		Y	7
7/20/2002 8:35	N/A	NPCC-Ontario	Independent Electricity Market Operator	Y	Y	N	OSL	0	N/A	Equipment malfunction	On two separate instances a large generating station lost its 250 volt DC system, which resulted in the complete loss of all system protection (primary and backup protection). This resulted in an operating security limit violation.	N	N	No FIRM demand interruption reported	Y	
7/20/2002 12:40	7.6	NPCC	Consolidated Edison Company of New York	Y	Y	N	INT	63,500	278	Equipment failure	On July 20, 2002 at 1240 EDT, system protection removed from service the feed into a distribution substation due to a transformer fire. This caused electric service to 63,500 customers to be interrupted. By 2012 EDT, electric service to all customers was restored.	Y	Y		Y	1,416
7/26/2002 15:19	3.7	Commonwealth Edison Company	MAIN	Y	Y	Y	UO	0	N/A	Equipment failure - fuel supply	On July 26, 2002 at 1519 CDT, system protection removed from service multiple generating units due to a natural gas supply interruption, which occurred during emergency repairs by the natural gas supplier.	N	N	No FIRM demand interruption reported	Y	
7/27/2002 19:15	0.2	WECC-AZNMSNV	Arizona Public Service Company	Y	N	N	INT	1,000	15	Weather - lightning	On July 27, 2002 at 1915 MST, system protection removed from service two high voltage transmission buses at a major generating station due to lightning strikes. This event caused a loss of station service to other buses and the subsequent removal from service of multiple generating units. Electric service was curtailed to about 1,000 customers. Service was restored by 1928 MST.	Y	Y		Y	2
7/29/2002 23:27	N/A	NPCC	Reliant Resources and Consolidated Edison Company of New York	Y	Y	N	INT	9,000	N/A	Equipment failure	On July 29, 2002 at 2327 EDT, system protection removed from service several generating units due to the catastrophic failure of a generator step up transformer. As a result of this event an undetermined amount of firm customer demand was lost.	N	N	No FIRM demand interruption reported	Y	
7/30/2002 13:00	N/A	NPCC	New York Independent System Operator	Y	Y	N	PA	N/A	N/A	Weather - heat and high demand	On July 30, 2002 between 1300 and 1800 EDT, a control area issued public appeals requesting voluntary curtailment of electricity usage as a result of a forecasted capacity shortage during a heat wave.	N	N	Public Appeal	Y	

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7/31/2002 13:17	0.3	WECC-NWPP	British Columbia Hydro Power Authority	N	N	N	INT	50,000	240	Human error	On July 31, 2002 at 1317 PDT, electric service was interrupted to about 50,000 customers because a new remote terminal unit (RTU) had a corrupted database. The utility was replacing an existing RTU with a new unit. However, a portion of the new RTU's database was corrupted and, when the RTU was activated, it caused part of a manual undervoltage load shedding scheme to operate. By 1337 PDT, electric service to all customer was restored.	Y	Y		Y	54
8/1/2002 14:00	58.0	ECAR	Consumers Energy Company	Y	Y	Y	INT	114,500	100	Weather - severe storms	At about 1400 EDT on August 1, 2002, severe storms caused wide-spread customer outages throughout portions of Michigan. About 114,500 customers were affected.	Y	Y		Y	3,885
8/2/2002 3:45	0.2	NPCC-Quebec	Hydro-Quebec TransEnergie	N	Y	N	INT	N/A	848	Weather - lightning	On August 2, 2002 at 1545 EDT, system protection removed from service two high voltage transmission lines due to lightning strikes. As a result, electric service to 848 MW of firm industrial demand was interrupted.	Y	Y		Y	104
8/2/2002 9:47	N/A	WECC-AZNMSNV	El Paso Electric Company	Y	N	N	INT	350,000	1,071	Contractor accident	On August 2, 2002 at 0947 MDT, system protection removed from service a high voltage transmission line due to a dump truck contacting a tower structure. Within 6 seconds, system protection removed from service two additional high voltage transmission lines and a HVDC tie. In addition, system protection removed from service 317 MW of internal generation. As a result of this event, electric service to about 350,000 customers (1,017 MW) was interrupted. By 1533 MDT, electric service to all customers was restored.	N	Y		Y	
8/9/2002 8:23	3.8	FRCC	Lake Worth Utilities	Y	N	N	INT	25,000	51	Animal contact	On August 9, 2002 at 0830 EDT, system protection removed from service a distribution feeder circuit due to an animal contact. System protection removed a second distribution feeder from service at about the same time, resulting in all of the utility's internal generation to be removed from service. The loss of generation caused a complete system shutdown. By 1213 EDT, electric service to all customers was restored.	Y	Y		Y	131
8/14/2002 16:31	0.2	NPCC-Quebec	Hydro-Quebec TransEnergie	N	Y	N	INT	8	1,060	Weather - lightning suspected	On August 14, 2002 at 1631 EDT, system protection removed from service a high voltage transmission line due to lightning strikes. Because of voltage fluctuations caused by the opening of this line, about 1,060 MW of firm customer demand was lost. By 1641 EDT, electric service to all customers was restored.	Y	Y		Y	118
8/26/2002 10:24	0.3	WECC-AZNMSNV	Tucson Electric Power Company	Y	N	N	INT	50,000	270	Equipment failure	On August 26, 2002 at 1024 MST, electric service was interrupted to about 50,000 customers when a special protection scheme (SPS) inadvertently operated. The SPS is used to detect an open tie line and then perform specific remedial actions, including shedding customer demand to prevent a voltage collapse. Because of an earlier problem, a maintenance crew was inspecting a circuit breaker to determine if the circuit breaker was fully open. When the maintenance crew operated the circuit breaker, which was isolated, the SPS detected an open tie and initiated remedial actions including the shedding of customer demand. By 1040 MST, electric service to all customers was restored	Y	Y		Y	48
8/28/2002 14:09	1.5	FRCC	Lake Worth Utilities	Y	N	N	INT	25,000	68	Weather - lightning	On August 28, 2002 at 1409 EDT, electric service to 25,000 customers was interrupted due to severe weather and multiple lightning strikes. Because of the system configuration as a result of previous disturbances in July and August, 2002, the loss of a single distribution feeder led to a complete system shutdown. By 1538, electric service to all customers was restored. In addition, the system configuration was returned to normal with the installation of a new transformer and the completion of repairs due to the prior disturbances.	Y	Y		Y	68
9/3/2002 14:52	3.0	WECC-CAMX	California Independent System Operator	Y	Y	N	UO	0	N/A	Wild fires	On September 3, 2002 at 1449 PDT, system protection removed from service a high voltage transmission line due to a wild fire burning in a common right-of-way. At 1452 PDT, another high voltage transmission line, located in the same corridor, was removed from service by system protection. This line opening caused an immediate overload on a third high voltage transmission line associated with the same corridor. To alleviate the overload, the control area operator ordered 892 MW of interruptible demand shed in the area. By 1750 PDT, electric service to all interruptible demands was restored. No firm demand was shed.	N	N	No FIRM demand interruption reported	Y	
9/9/2002 17:09	0.3	NPCC-Ontario	Independent Electricity Market Operator	Y	Y	N	VR	0	400	Weather - hot and humid	On September 9, 2002 between 1709 and 1728, a 3% voltage reduction was implemented due to high system demands due to hot and humid weather. This action was required to reduce the flows over several transmission lines between two subregions of the control area while interchange transactions curtailments were being requested. The control area operator saw about a 400 MW demand relief from the voltage reduction.	N	N	Voltage reduction	Y	85
9/15/2002 18:10	14.2	MAPP	Minnesota Power Company	Y	Y	Y	UO	0	N/A	Equipment malfunction	On September 15, 2002 at 1810 EDT, a special secondary protection scheme removed from service two generating units without receiving the expected initiating signal. The SPS has been disabled to prevent further malfunctions until the cause can be determined. Other redundant systems remained operable.	N	N	No FIRM demand interruption reported	Y	

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9/26/2002 5:48	0.5	WECC-NWPP	Western Electric Coordinating Council - NWPP	Y	N	N	UO	0	N/A	Insulator contamination	On September 26, 2002 at about 0546 MDT, system protection removed from service a high voltage transmission line after an insulator flashover due to contamination. Before the system operators could restore this line, system protection removed from service a second high voltage line due to a broken static wire. Because of the loss of both lines, a special protection scheme, designed to protect local generating units, removed from service three generating units. □ During the event, system frequency declined from 59.90 Hz to 59.76 Hz. at 0548:21 MDT. The frequency recovered to 59.862 Hz and then declined to 59.762 Hz at 0548:48. The second frequency excursion was unrelated to this event and was due to the loss of another generating unit outside of the control area where the original events occurred	N	N	No FIRM demand interruption reported	Y	
10/3/2002 3:33	212.4	SERC-Entergy	Entergy Corporation	Y	N	N	INT	242,910	N/A	Hurricane Lili	On October 3, 2002 at about 0333 CDT, Hurricane Lili caused wide-spread customer outages along the Louisiana coast. The storm then moved ashore and continued to cause damage and wide-spread customer outages throughout Louisiana and portions of Mississippi. About 243,000 customers were affected by this storm.	N	Y		N	
10/3/2002 8:00	88.6	SPP	Lafayette Utilities System	Y	Y	N	INT	55,000	212	Hurricane Lili	On October 3, 2002 at about 0800 CDT, Hurricane Lili caused wide spread customer outages along the Louisiana coast. The storm then moved ashore and continued to cause damage and wide-spread customer outages throughout Louisiana and portions of Mississippi. About 55,000 customers were affected by this storm.	Y	Y		N	12,587
10/3/2002 10:10	109.8	SPP	Cleco Power, LLC	Y	Y	N	INT	164,500	N/A	Hurricane Lili	On October 3, 2002 at about 1010 CDT, Hurricane Lili caused wide spread customer outages along the Louisiana coast. The storm then moved ashore and continued to cause damage and wide-spread customer outages throughout Louisiana and portions of Mississippi. About 164,500 customers were affected by this storm.	N	Y		N	
10/8/2002 15:31	N/A	Bonneville Power Administration Transmission Services	WECC-NWPP	Y	Y	N	UO	0	N/A	Suspected human error & equipment failure	On October 8, 2002 at 1531 PDT, system protection inadvertently removed from service three high voltage transmission lines due to a breaker failure relay at one of the substations involved. At the time of this event, another high voltage line was out of service for maintenance. A maintenance crew was working on a circuit breaker, which had been isolated and which may have caused a breaker failure relay to operate. This event caused a special protection scheme to initiate remedial actions, which was designed to protect various transmission and generating facilities in the region. Because of the system frequency excursion, under-frequency protection shed some firm customer demand. In addition, about 325 MW of interruptible demand was shed. The system frequency declined to 59.637 Hz and returned to normal by 1545 PDT.	N	N	No FIRM demand interruption reported	Y	
10/21/2002 7:43	N/A	MAPP-Canada	Manitoba Hydro Transmission Services	N	Y	Y	UO	0	N/A	Equipment failure	On October 21, 2002 at 0743 CDT, a high voltage dc transmission line power reduction scheme operated when system operators removed a high voltage transmission line from service. Because a second high voltage transmission line was still in service, the scheme should not have operated. No generation or customer demand was interrupted due to this false operation.	N	N	No FIRM demand interruption reported	Y	
10/31/2002 7:51	2.3	NPCC-Quebec	Hydro-Quebec TransEnergie	N	Y	N	UO	0	250	Equipment failure	On October 31, 2002 at 0751 EST, system protection removed from service a high voltage dc Tie between two systems while exporting 1,130 MW of energy. No generation or customer demand was lost due to this event.	Y	Y		Y	388
11/6/2002 22:00	74.0	WECC-CAMX	California Independent System Operator, Pacific Gas & Electric Co.	Y	Y	N	INT	877,000	N/A	Weather - heavy rain and wind	On November 6, 2002 at about 2200 PST a severe winter storm caused wide spread customer outages throughout much of California. Most of the damage sustained was in the distribution system, while some transmission facilities were also affected. About 877,000 customers were affected by this storm. About 1,000 MW of generation was curtailed due to high waves along the coast.	N	Y		Y	
11/7/2002 6:34	6.7	NPCC-Quebec	Hydro-Quebec TransEnergie	N	Y	N	INT	1	250	Weather - snow and strong winds	On November 7, 2002 at 0634 EST, system protection removed from service two high voltage transmission lines due to severe weather (strong winds and snow). In addition, system protection removed from service a total of 532 MW of generation at two generating stations. Because of these actions, one large industrial customer was affected.	Y	Y		Y	1,122
11/22/2002 11:01	0.0	NPCC-Quebec	Hydro-Quebec TransEnergie	N	Y	N	UO	0	N/A	Equipment failure and relay misoperation	On November 22, 2002 at 1101 EST, system protection inadvertently removed from service a high voltage transmission line. It is not known why system protection operated. Because of this misoperation, a special protection system, designed to prevent overload of a second high voltage transmission line, removed 800 MW of generation from service. No customer demand was shed because of this event.	N	N	No FIRM demand interruption reported	Y	
12/3/2002 18:30	148.0	SERC-Entergy	Entergy Corporation	Y	N	N	INT	43,000	N/A	Weather - ice storm	On December 3, 2002 at about 0630 CST, a major ice storm caused wide spread customer outages throughout Arkansas. Most of the damage sustained occurred in the distribution systems. However, some transmission facilities were also damaged. About 43,000 customers were affected by this storm.	N	Y		N	
12/4/2002 20:05	N/A	SERC-VACAR	Duke Energy Corporation	Y	N	N	INT	1,140,000	7,200	Weather - snow, sleet, ice	On December 4, 2002 at about 0805 CST, a major winter storm (snow/ice/sleet) caused wide spread customer outages throughout North and South Carolina. Most of the damage sustained occurred in the distribution systems. However, some transmission facilities were also damaged. About 1,140,000 customers were affected by this storm.	N	Y		N	
12/5/2002 6:00	162.0	SERC-VACAR	Carolina Power & Light Company	Y	Y	N	INT	464,000	2,400	Weather - snow, sleet, ice	On December 5, 2002 at about 0600 CST, a major winter storm caused wide spread customer outages throughout North and South Carolina. Most of the damage sustained occurred in the distribution systems. However, some transmission facilities were also damaged. About 464,000 customers were affected by this storm.	Y	Y		N	260,469

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12/11/2002 13:09	34.8	SERC-VACAR	Dominion Virginia Power	Y	Y	N	INT	90,000	63	Weather - freezing rains	On December 11, 2002 at about 1300 EST, a major winter storm (freezing rain) caused wide spread customer outages throughout Virginia. Most of the damage sustained occurred in the distribution systems. About 90,000 customers were affected by this storm.	Y	Y		Y	1,470
12/14/2002 11:00	101.0	WECC-CAMX	California Independent System Operator, Pacific Gas & Electric Co.	Y	Y	N	INT	2,100,000	180	Weather - heavy rains and winds	On December 14, 2002 at about 1100 PST a severe winter storm caused wide spread customer outages throughout northern and central California. The storm continued through Sunday night and into Monday December 16, 2002. Most of the damage sustained was in the distribution system, while some transmission facilities were also affected. About 2,100,000 customers were affected by this storm.	Y	Y		N	12,181
12/19/2002 6:00	35.0	WECC-CAMX	California Independent System Operator, Pacific Gas & Electric Co.	Y	Y	N	INT	385,000	56	Weather - heavy rains and winds	On December 19, 2002 at about 1100 PST a severe winter storm caused wide spread customer outages throughout northern and central California. This was the second severe winter storm in the past week. Most of the damage sustained was in the distribution system, while some transmission facilities were also affected. About 385,000 customers were affected by this storm.	Y	Y		Y	1,313
12/25/2002 10:00	94.5	MAAC	Metropolitan Edison Company	Y	Y	N	INT	95,630	N/A	Weather - heavy snow	On December 25, 2002 at about 1000 EST, a major winter snowstorm caused wide spread customer outages throughout areas of Pennsylvania. There was over 12 inches of snow accumulation, which caused trees to fall into the distribution system causing most of the outages. About 95,630 customers were affected by this storm.	N	Y		Y	
12/25/2002 17:00	79.0	MAAC	PPL Electric Utilities	Y	Y	N	INT	166,000	250	Weather - heavy snow	On December 25, 2002 at about 1700 EST, a major winter snowstorm caused wide spread customer outages throughout areas of Pennsylvania. Snow and ice caused conductor damage from falling trees. About 166,000 customers were affected by this storm.	Y	Y		Y	13,230
12/26/2002 12:02	N/A	WECC-NWPP	British Columbia Hydro Power Authority	N	N	N	INT	0	862	Weather - severe storm, ice	On December 26, 2002 at about 1202 PDT, system protection removed from service a high voltage transmission line when ice accumulation caused a conductor to sag into trees. The substation bus configuration was such that the loss of this circuit interrupted the ac power flow into a specific area of the control area's service area. This portion of the control area's transmission system now was asynchronously connected to the rest of its transmission system and was generation deficient. The system frequency dropped and surged three times before the electricity supply into the area was stabilized. Under-frequency protection shed about 862 MW of firm customer demand	N	N	Restoration Time Unknown	Y	
1/3/2003 14:10	2.5	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Inadvertent trip	On January 3, 2003 at 1410 EST, system protection inadvertently removed from service two high voltage transmission lines due to a maintenance procedure error. As a result of this event, system protection removed from service 1,749 MW of generation. No customer demand was lost due to this event.	N	N	No FIRM demand interruption reported	Y	
1/18/2003 23:04	0.8	NorthWestern Energy - Montana	WECC-NWPP	Y	N	N	UO	0	N/A	SPS Misoperation	On January 18, 2003 at 2304, two generating units tripped off line due to a RAS scheme misoperation. The frequency deviation went to 59.849 Hz and returned to pre-disturbance level of 59.994 Hz by 2319 MST. Both generating units were returned to service by 2349 MST.	N	N	No FIRM demand interruption reported	Y	
1/19/2003 0:12	0.1	NorthWestern Energy - Montana	WECC-NWPP	Y	N	N	UO	0	N/A	SPS Misoperation	On January 19, 2003 at 0012, three generating units tripped off line due to a RAS scheme misoperation. The frequency deviation went to 59.908 Hz and returned to pre-disturbance level by 0019 MST.	N	N	No FIRM demand interruption reported	Y	
1/24/2003 7:00	1.0	Jacksonville Electric Authority	FRCC	Y	N	N	VR	N/A	N/A	Cold weather	On January 24, 2003 at 0700, a Florida utility implemented a 5% voltage reduction for control area demand relief due to extremely cold weather. At 0800, the voltage reduction was cancelled.	N	N	No FIRM demand interruption reported	Y	
2/3/2003 23:19	4.1	Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	UO	0	N/A	Weather - Freezing rain and insulator contamination	During the evening of February 3, 2003, five hours of freezing rain occurred concentrated around a major high voltage switching-center. This weather, followed by warming temperatures and combined with suspected insulator contamination, resulted in system protection removing from service various transmission elements. Because of the initial faults, the system operators readjusted area generation so that the transmission system could withstand any subsequent contingencies, which could lead to additional separations. Subsequent to this, further faults did occur, which caused a separation main high voltage transmission system between two areas of the system. Restoration efforts were hampered until warming temperatures and rain melted ice. No generation or customer demand was lost during this event.	N	N	No FIRM demand interruption reported	Y	
2/13/2003 11:08	6.4	PacifiCorp East	WECC-NWPP	Y	N	N	UO	200,000	700	Dump Truck contacting tower structure	Status before the disturbance: There was scheduled maintenance to replace an existing high voltage step down transformer at a switching center adjacent to this incident. On February 13, 2003 at 11:08 MST, system protection removed two transmission lines when a third-party dump truck struck a tower structure causing a static line to fall into the transmission lines. As a result of this accident, system protection removed from service the remaining high voltage step down transformer, which caused the loss of electric service to approximately 200,000 customers. The system frequency rose to 60.01 Hz. In addition, system protection removed from service multiple generating units. The system frequency then declined to 59.970 Hz and recovered to its pre-disturbance level within 8 seconds. By 1730 MST, all electric service to customers was restored and all generating units returned to service.	Y	Y		Y	2,986

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2/23/2003 17:55	11.0	Los Angeles Department of Water & Power	WECC-CAMX	Y	N	N	UO	1	30	Static wire down by airplane contact	Status before the disturbance: The system was being operated normally with the exception that a single high voltage transmission line was out of service for scheduled maintenance. On February 23, 2003 at approximately 1755 PST, system protection removed from service a high voltage transmission line due to an airplane severing a static wire between two tower structures. Concurrent with this incident, system protection removed from service another high voltage transmission line and both poles of a nearby high voltage dc transmission line. In addition, system protection removed from service some generating units within the region, and a single industrial customer shed approximately 30 MW of demand. The system frequency ranged from 59.980 Hz to 59.799 Hz and was normal within 12 minutes.	Y	Y		Y	222
2/27/2003 11:32	92.5	Duke Energy Corporation	SERC-VACAR	Y	N	N	INT	350,000	1,000	Weather - Major ice storm	On February 27, 2003, a major ice storm caused system-wide power outages to large portions of the distribution system within several counties. Between 52,000 and 350,000 customers were affected by these power outages.	Y	Y		Y	61,953
3/2/2003 5:47	0.4	Comision Federal de Electricidad	WECC-CAMX	Y	Y	N	UO	0	N/A	Line fault	Status before the disturbance: The system was being operated normally with the exception that a single high voltage transmission line was out of service for scheduled maintenance. On March 2, 2003 at 0547, system protection removed from service a high voltage transmission line, which caused a small island between two portions of the Interconnection. At 0609, the islanded system paralleled to the Interconnection. No generation or customer demand lost because of this incident.	N	N	No FIRM demand interruption reported	Y	
3/7/2003 19:18	20.7	Public Service Company of New Mexico	WECC-AZNMSNV	Y	N	N	UO	0	N/A	Static wire down by airplane contact	On March 7, 2003 at 1918 MST, system protection removed from service two high voltage transmission lines, which run parallel in the same right-of-way. The cause of this incident was found to be a small airplane contacting a static wire on one circuit and carrying into the adjacent circuit. In conjunction with this incident, a sub-transmission bus differential relay mis-operated in an adjacent system at a back-to-back dc converter station. This caused system protection to remove from service a third high voltage transmission line in the system where the incident occurred. No generation or customer demand was lost due to this incident.	N	N	No FIRM demand interruption reported	Y	
3/10/2003 23:23	0.4	Comision Federal de Electricidad	WECC-CAMX	Y	Y	N	INT	0	N/A	Line fault	Status before the disturbance: The system was being operated normally with the exception that a single high voltage transmission line was out of service for scheduled maintenance. There was also a report of heavy fog in the area of the fault. On March 10, 2003 at 2323 PST, system protection removed from service a high voltage transmission line, which caused a small island between two portions of the Interconnection. At 2345, the islanded system paralleled to the Interconnection. No generation or customer demand was lost due to this incident.	N	N	No FIRM demand interruption reported	Y	
3/21/2003 18:38	23.0	California Independent System Operator, Southern California Edison Company	WECC-CAMX	Y	Y	N	UO	1	300	Transformer failure	On March 21, 2003 at 1838 PST, system protection removed from service one bus and a high voltage step-down transformer due to an internal fault and resulting fire on the transformer. At 1847, system protection removed from service another bus and the remaining two high voltage step-down transformers due to the fire. As a result of this incident all high voltage transmission lines, which were connected to these buses, were opened ended, and the three high voltage step-down transformers were taken out of service. In addition, some firm customer demand was lost at a nearby site due to low area voltage. The system frequency varied from 59.991 Hz to 60.019 Hz and returned to normal within two minutes.	Y	Y		Y	4,630
3/22/2003 6:50	2.4	British Columbia Hydro & Power Authority	WECC-NWPP	N	N	N	INT	135,000	1,080	Line fault	On March 22, 2003 at 0650 PST, system protection removed from service two high voltage transmission lines. As a result of this incident, two additional high voltage transmission lines were removed from service by system protection to protect the island's high voltage transmission system. This caused one area of the system to become islanded from the main system. However, an asynchronous high voltage dc transmission line remained in service to supple some area loads. System protection removed from service some area bulk transmission loads to prevent overloading the low voltage transmission lines in the northern section of the islanded area. Because the islanded area was generation deficient, some underfrequency load shedding occurred. Some additional generating units were removed from service by system protection, further reducing area generation. The frequency in the islanded area declined to 56.94 Hz and rose to 61.29 Hz after the underfrequency load shedding occurred. The high voltage dc transmission line's frequency controller reduced imports to correct the frequency to 60.00 Hz. The islanded area was synchronized to the main system using two normally open low voltage transmission lines. As area generation was returned to service, customer loads were resorted. By 0914, all customer loads were restored. Electric service was interrupted to approximately 135,000 customers by this incident	Y	Y		Y	1,737

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3/26/2003 0:19	1.5	PacifiCorp Western System	WECC-NWPP	Y	N	N	UO	0	N/A	Human error	On March 26, 2003 at 0919 PST, three generating units were removed from service by system protection due to human error. At about 0924 PST, a fourth generating units was removed from service by system protection. The cause of this fourth unit outages was not determined. The system frequency varied from 59.84 Hz to 59.95 Hz and was normal by 0932 PST. There were no additional facilities or customer loads affected by this incident.	N	N	No FIRM demand interruption reported	Y	
4/4/2003 19:00	70.0	Consumers Energy	ECAR	Y	Y	Y	INT	425,000	300	Weather - severe ice storm	On Thursday April 3, 2003, a stationary front extended from west to east across mid-Michigan and produced a heavy, icy precipitation that affected the Flint and tri-city area of Saginaw, Midland and Bay City. The front remained in place throughout the day on Friday, producing a mixture of precipitation. Friday evening, as temperatures dropped, the area and intensity of the icy precipitation grew. Areas minimally affected on Thursday including Grand Rapids, Hastings, Greenville, Alma, Lansing and Owosso received the most significant damage from this second wave of icy precipitation. Electric service was interrupted to approximately 425,000 customers due to the storm, with about 196,000 off at one time. Most electric service was restored by 2400 hours on April 8, 2003.	Y	Y		Y	14,070
4/7/2003 0:19	0.1	California Independent System Operator	WECC-CAMX	Y	Y	N	UO	N/A	650	Unknown	On April 7, 2003 at 0019 PDT, one of two generating unit's circuit breakers failed to open as the generating plant operator was removing the unit from service. At about the same time, system protection removed from service three nearby high voltage transmission lines. As a result of this some area customer demand was shed. By 0027 PDT, all customer demand was restored.	Y	Y		Y	58
4/15/2003 11:39	4.3	ERCOT ISO, CenterPoint Energy, Bryan Texas Utilities	ERCOT	Y	Y	N	INT	68,530	212	Erroneous trip signal	Status before the disturbance: The system was operating normally with the exception of a scheduled maintenance outage of one pole of a high voltage DC transmission line. There were high winds with a mix of snow, rain and lightning activity in the area. ERCOT disturbance - April 15, 2003 On Tuesday April 15, 2003, at about 1130 hours, during the switching of an unrelated 345 kV transmission line for scheduled maintenance, an apparently erroneous trip signal was sent to a remote 345 kV switching device at a generating station. The remote 345 kV switching device failed to open. As a result of this incident, the breaker failure scheme at the generating station operated for both 345 kV buses. Consequently, system protection removed from service several 345 kV lines and two 345/138 kV autotransformers. This resulted in an inadequate supply of power to the 138 kV transmission system in the surrounding area, and depressed the 138 kV voltages below acceptable levels in the area. In addition, system voltage effects caused by the disturbance resulted in about 330 MW of customer load being shed. During the disturbance, communications between the generating station, and the transmission operator's control center was interrupted and the system operators were unable to obtain real-time data from the 345 kV switchyard. This loss of real-time data meant that a visual inspection of the 345 kV switchyard would be required before system operators could begin restoration. At about 1600 hours the system and all customer load was restored.	Y	Y		Y	618
5/2/2003 17:00	19.0	Duke Energy Company	SERC-VACAR	Y	N	N	INT	139,000	1,500	severe weather	On May 2, 2003, a series of thunderstorms, lightning and strong winds crossed the service territory. By about 2040, electric service to approximately 139,000 customers was interrupted due to these storms (approximately 1,500 MW). Restoration efforts started with the first interruptions and completed by 12:00 on May 23, 2003.	Y	Y		Y	19,095
5/3/2003 0:18	0.3	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	SPS Misoperation	On May 3, 2003 at 0018 EDT, a special protection scheme at a generating station removed five generating units from service because a trip signal was sent when a high voltage transmission line was removed from service for voltage control. The system frequency went to 59.00 Hz and immediately recovered to normal. The utility involved determined that the cause of this incident that the default set points for the generating units were implemented as a result of the SPS's main computer being removed from service because of a problem. When the high voltage transmission line was manually removed from service for voltage control, the open line detection scheme of the SPS functioned normal and sent the trip signal to the generating units. The set points should have been set to zero during the outage of the main SPS computer, which would have prevented this incident. The utility involved is investigating the reason for the main computer outage. No other facilities or customer demand was lost due to this incident.	N	N	No FIRM demand interruption reported	Y	
5/4/2003 23:32	15.8	Tennessee Valley Authority	SERC-TVA	Y	N	N	INT	14,825	N/A	Tornados	Between 23:32 EDT on May 4, 2003 to 11:28 EDT on May 7, 2003, a series of tornadoes were reported to have caused damage to several high voltage transmission, subtransmission and distribution lines in four southern states. As a result of these tornadoes, electric service was interrupted to approximately 14, 825 customers. By 15:19 on May 6, 2003 all customer demand was restored.	N	Y		Y	
5/10/2003 21:53	N/A	Commonwealth Edison	MAIN	Y	Y	N	UO	N/A	N/A	Tornado	On May 10, 2003 at 21:52, a reported tornado caused damage to several high voltage transmission lines. No generation or customer demand was lost due to this incident.	N	N	No FIRM demand interruption reported	Y	

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5/11/2003 13:00	0.0	Commonwealth Edison	MAIN	Y	Y	N	INT	65,000	N/A	Severe weather	At approximately 13:00 CDT on May 11, 2003, electric service to approximately 50,000 customers was interrupted as a result of strong winds. Most customer outages were distribution related problems.	N	Y		Y	
5/15/2003 2:54	3.6	ERCOT ISO	ERCOT	Y	Y	N	INT	419,863	1,549	Insulator failure, system protection failure	On May 15, 2003 at about 0254 CDT, insulator contamination caused a fault on a high voltage transmission line near a large power plant in north Texas. System protection failures on the line resulted in loss of a large amount of generation, transmission lines, and customer demand throughout most of the ERCOT region. The remaining generation was insufficient to serve the load on the grid at that time. Automatic underfrequency load shedding relaying located all across the ERCOT Region operated to reduce load and contain the disturbance. These control systems operated as designed, and all customer service was restored by approximately 0630.	Y	Y		Y	3,736
5/15/2003 14:00	N/A	Wisconsin Electric Power Company	MAIN	Y	Y	Y	PA	2	240	Flooding	On May 15, 2003 from 14:00 to 22:00 hours, a utility company issued public appeals for the reduction of customer demands. The utility company issued the public appeals due to the loss of area generation caused by flooding. Approximately 240 MW of interruptible load was shed, which involved two customers.	N	N	Public Appeal	Y	
5/29/2003 17:04	0.4	Los Angeles Department of Water & Power, Bonneville Power Administration	WECC-CAMX	Y	N	N	UO	0	N/A	Equipment failure	Status before the disturbance: On May 29, 2003 at about 1656 PDT, a single pole of a high voltage dc transmission line momentarily blocked by system protection due to an apparent lightning strike. The special protection scheme operated correctly inserting various series and shunt capacitors and operating a special Transient Excitation Boost scheme at a generating plant to control system voltages and power flows. Disturbance: On May 29, 2003 at about 1704 PDT, a high voltage dc converter station power factor capacity switcher (circuit breaker) failed while opening the switcher in response to a signal from the reactive power controller. This fault was properly cleared by system protection. However, the fault caused a severe voltage drop in the area, which caused the loss of one pole of the high voltage dc transmission line. Again the special protection scheme operated correctly inserting various series and shunt capacitors and operating a special Transient Excitation Boost scheme. In addition, some area generating units were removed from service, as designed, by the special protection scheme. These actions are taken to protect various transmission elements, control voltages and power flows during an outage of the high voltage dc transmission line. The system frequency recovered to pre-disturbance level by 1714 PDT. There were no other facilities or customer loads lost as a result of this incident.	N	N	No FIRM demand interruption reported	Y	
6/22/2003 23:44	0.3	Minnesota Power Company	MAPP	Y	Y	Y	UO	0	N/A	Line fault and system protection misoperation	On June 22, 2003 at 23:44 CDT, system protection removed from service a single high voltage transmission line due to a permanent fault. Because of abnormal operating conditions, the trip, and subsequent reclosure of this transmission line caused several protection system misoperations to occur resulting in system protection removing four additional high voltage transmission lines. As a result of these operations, generation from a single generating station was forced through a single high voltage transmission line, which resulted in overloading this transmission line. A generation runback scheme automatically initiated the runback of two generating units. Before the runback sequence was completed, the system operator reclosed one of the high voltage transmission lines, which eliminated the need for further generation reduction. By June 23, 2003 at 00:04 CDT, the system was normal. No generation or customer demand was lost due to this event	N	N	No FIRM demand interruption reported	Y	
6/24/2003 14:03	0.6	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	N/A	260	Smoke contamination	On June 24, 2003 at 1339 EDT, system protection momentarily removed from service a high voltage transmission line due to a faulted shunt reactor. At 1400 EDT, the line was manually removed from service to isolate and inspect the shunt reactor. When the line was removed from service a special protection scheme (SPS) timer was armed. At 1403 EDT, system protection removed from service an adjacent high voltage transmission line due to smoke contamination caused by the burning shunt reactor on the other line. As a result of the second line being removed from service, the SPS correctly initiated generator tripping of 2,200 MW of generation from a nearby generating station. The system frequency declined to 58.66 Hz, which caused underfrequency relaying to shed approximately 260 MW of firm demand. At 1413 EDT, all generating units were restored. At 1439 EDT, all customer demand was restored.	Y	Y		Y	105
7/1/2003 15:15	0.3	Arizona Public Service Company	WECC-AZNMSNV	Y	N	N	INT	48,000	1,000	Equipment failure	On July 1, 2003 at 1515 MST, system protection removed from service a high voltage bus and two step-down transformers due to a catastrophic failure of the circuit breaker for a high voltage line shunt capacitor bank. At about the same time, system protection removed from service two additional high voltage transmission lines. As a result of removing the high voltage step down transformer, approximately 1,000 MW of firm demand was lost. Approximately 48,000 customers were affected by this event. 1533 MST restored all transmission lines and the electric service to all customers.	Y	Y		Y	201

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7/17/2003 19:00	N/A	Commonwealth Edison	MAIN	Y	Y	N	INT	80,000	N/A	Severe Weather	During the evening of July 17, 2003, severe storms with high winds moved across northern Illinois causing wide-spread customer outages. Most customer outages were south of the Chicago metro area and the southeastern portion of the service territory. Approximately 50,000 customers were affected by this event.	N	Y		Y	
7/21/2003 17:15	30.7	PPL Electric Utilities	MAAC	Y	Y	N	INT	185,000	1,000	Severe weather	On July 21, 2003 at 1730 EDT, a severe thunder and lightning storm, with high winds, caused widespread customer outages through the night and into the next morning. Approximately 185,000 customers were affected by this storm.	Y	Y		Y	20,591
7/28/2003 18:54	1.7	Arizona Public Service Company, Salt River Project	WECC-AZNMSNV	Y	N	N	INT	90,000	440	Human error	On July 28, 2003 at 1854 MST, system protection removed from service a total of 2,687 MW of generation (five generating units). The generating units were located at four different generating stations within the immediate area. Because of the resulting frequency disturbance, the control area operator manually shed 440 MW of firm customer load and received an additional 400 MW of emergency assistance from a neighboring system. The system frequency was restored to normal by 1914 MST. A station ground switch was inadvertently left closed during routine switching at a high voltage transmission substation in an adjacent control area. Approximately 90,000 customers were affected by the manual load shedding. All customer load was restored by 2035 MST.	Y	Y		Y	496
7/30/2003 16:22	0.8	Minnesota Power	MAIN	Y	Y	Y	UO	N/A	N/A	Lightning	On July 30, 2003 at 1617 CDT, system protection removed a high voltage transmission line from service due to lightning. One terminal end closed successfully, however the other end remained open due to excessive phase angle across the open circuit breaker, which was in excess of the maximum allowed by the sync-check relay. This event resulted in an overload on two other high voltage transmission lines, which initiated a generator runback scheme. As generation was being reduced, system protection removed from service the two overloaded high voltage transmission lines due to a second lightning strike. The result of this event initiated a generating tripping scheme, and caused the islanding of a small area. Approximately 80 MW of load was balanced with generation available inside the islanded area. After the frequency was stabilized, several unsuccessful attempts were made to re-synchronize the island. At 1707 CDT, the islanded area was shut down manually by system operators. At 1709 CDT, all high voltage transmission lines were back in service.	N	N	No FIRM demand interruption reported	Y	
8/10/2003 14:09	744.2	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Weather - lightning	On 8/10/2003 at 1409 EDT, system protection simultaneously removed from service several high voltage transmission lines due to lightning. This event correctly initiated an special protection system, which removed a total of 776 MW of generation from service. AT 1409 EDT, all high voltage transmission lines were restored. No customer demand was lost due to this event.	N	N	No FIRM demand interruption reported	N	
8/12/2003 20:31	1.0	British Columbia Hydro and Power Authority	WECC-NWPP	N	N	N	INT	7,400	465	Equipment failure	On August 12, 2003 at 2031 PDT, system protection removed from service a high voltage transmission line due to a broken crossarm on one tower structure. This line is a single source of power for approximately 7,400 customers. In addition, system protection removed from service approximately 858 MW of area generation. As a result of the loss of generation, approximately 450 MW of industrial demand was shed. By 2131 PDT, all generation and customer demand was restored.	Y	Y		Y	312
8/13/2003 22:55	N/A	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Unknown	On August 13, 2003 at 22:55:04 system protection removed from service multiple generating units from a single generating plant. This caused a loss of 550 MW of generation and a transient frequency drop from 60 Hz to 59.58 Hz. There was no customer load lost because of this event.	N	N	No FIRM demand interruption reported	Y	
8/14/2003 15:00	74.0	Midwest ISO	Multiple Regions	Y	Y	Y	INT	N/A	18,500	Major blackout	On August 14, 2003 at 15:10 CDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed.	Y	N	Blackout Event, Note: Duplicate event of First Entergy, Consumers Power, Detroit Edison Blackout data	N	917,230
8/14/2003 16:09	38.8	Detroit Edison	ECAR	Y	Y	Y	INT	2,100,000	11,000	Major blackout	Added from EIA disturbance data	Y	N	Blackout Event	N	280,324
8/14/2003 16:09	44.9	Consumers Power	ECAR	Y	Y	Y	INT	101,000	1,007	Major blackout	Added from EIA disturbance data	Y	N	Blackout Event	N	30,294
8/14/2003 16:10	13.8	PJM Interconnection, LLC	MAAC	Y	Y	N	INT	N/A	4,100	Major blackout	Added from EIA disturbance data	Y	N	Blackout Event	N	38,000

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
8/14/2003 15:11	N/A	Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	INT	11,000,000	20,667	Major blackout	On August 14, 2003 at 16:10 EDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed. .	N	N	Blackout Event	N	
8/14/2003 16:10	31.8	FirstEnergy Corp.	ECAR	Y	Y	Y	INT	1,203,000	7,000	Major blackout	On August 14, 2003 at 16:10 EDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed.	Y	N	Blackout Event	N	149,298
8/14/2003 16:10	N/A	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	INT	N/A	100	Major blackout	On August 14, 2003 at 16:10 EDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed.	N	N	Blackout Event	N	
8/14/2003 16:10	35.6	ISO New England	NPCC-ISO-NE	Y	Y	N	INT	2,500	2,500	Major blackout	On August 14, 2003 at 16:10 EDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed.	Y	N	Blackout Event	N	59,602
8/14/2003 16:11	28.9	Consolated Edison Company of N.Y.	NPCC-NYISO	Y	Y	N	INT	3,125,350	11,202	Major blackout	On August 14, 2003 at 16:10 EDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed.	Y	N	Blackout Event	N	216,654
8/14/2003 17:10	1.2	New Brunswick Power	NPCC-Maritimes	Y	Y	N	INT	0	N/A	Major blackout	On August 14, 2003 at 16:10 EDT, the Northeastern United States and portions of Canada blacked out affecting electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. Approximately 61,800 MW of demand was lost as a result of the blackout that affected approximately 50,000,000 customers. A detailed investigation has been completed.	N	N	Blackout Event	N	
8/16/2003 12:00	9.0	Consolidated Edison Company of New York	SERC-Entergy	Y	N	N	PA	N/A	N/A	Insufficient capacity	As a result of the August 14, 2003 Northeastern blackout, on August 16, 2003 at 12:00, the New York ISO called for public appeals to help reduce customer demand while restoration efforts were still under way.	N	N	Public Appeal	N	
8/17/2003 19:48	1.4	Entergy Energy Services	SPP	Y	Y	N	INT	65,000	500	Equipment failure	On August 17, 2003 at 1948 CDT, system protection removed from service high voltage buses at a generating station because of a failed current transformer (CT). Due to the failure of the station batteries, system protection removed several high voltage transmission lines in the immediate vicinity of the initial incident. These subsequent events resulted in the loss of 350 MW of customer load and affected approximately 65,000 customers.	Y	Y		Y	452
8/26/2003 21:26	0.2	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Weather - lightning	On August 26, 2003 at 2126 EDT, system protection removed from service two high voltage transmission lines and multiple generating units at a single generating station due to lightning striking the transmission lines. As a result of this incident approximately 1,075 MW of generation was lost. No customer load was affected by the incident.	N	N	No FIRM demand interruption reported	Y	
9/4/2003 13:53	0.0	Hydro-Quebec-TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Unknown	On September 4, 2003 at 1353 EDT, system protection removed from service a single high voltage transmission line due to an unknown cause. As a result of this incident, a special protection scheme initiated the tripping of two generating units by single contingency as designed. This resulted in the loss of approximately 600 MW of generation. No customer load was affected by this incident.	N	N	No FIRM demand interruption reported	Y	
9/15/2003 1:32	0.3	PECO, Baltimore Gas and Electric	MAAC	Y	Y	N	UO	45,000	400	Weather - lightning, relay misoperation	On September 15, 2003 at 0132 EDT, a system protection failure following a lightning strike on a high voltage transmission line resulted in the loss of several high voltage transmission lines. As a result of this incident, system protection removed from service approximately 2,100 MW of generation involving multiple generating units, 875 MW of pump load, and 400 MW of customer load. Approximately 45,000 customers were interrupted because of this incident.	Y	Y		Y	87
9/18/2003 8:20	374.7	Dominion - Virginia Power, North Carolina Power	SERC-VACAR	Y	Y	N	INT	1,800,000	6,512	Hurricane Isabel	On September 18, 2003 starting at about 0820 EDT, Hurricane Isabel caused widespread customer interruptions and damaged multiple distribution and transmission lines and facilities. As a result of the damage caused by the hurricane approximately 6,500 MW of customer load was lost affecting more than 1,800,000 customers.	Y	Y		N	1,634,686
9/18/2003 11:45	96.2	Carolina Power & Light (Progress Energy)	SERC-VACAR	Y	N	N	INT	320,000	1,655	Hurricane Isabel	On September 18, 2003 starting at about 1145 EDT, Hurricane Isabel caused widespread customer interruptions and damaged multiple distribution and transmission lines and facilities. As a result of the damage caused by the hurricane approximately 1,655 MW of customer load was lost affecting more than 320,000 customers.	Y	Y		N	106,727

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MidwestISO
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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
9/18/2003 12:00	132.0	Conectiv Power Delivery	MAAC	Y	Y	N	INT	120,000	600	Hurricane Isabel	On September 18, 2003 starting at about 1200 EDT, Hurricane Isabel caused widespread customer interruptions and damaged multiple distribution and transmission lines and facilities. As a result of the damage caused by the hurricane approximately 600 MW of customer load was lost affecting more than 120,000 customers.	Y	Y		N	53,057
9/18/2003 21:00	99.0	PPL EU	MAAC	Y	Y	N	INT	350,000	1,300	Hurricane Isabel	On September 18, 2003 starting at about 2100 EDT, Hurricane Isabel caused widespread customer interruptions and damaged multiple distribution and transmission lines and facilities. As a result of the damage caused by the hurricane approximately 1,300 MW of customer load was lost affecting more than 350,000 customers.	Y	Y		N	86,229
9/28/2003 23:58	88.0	Nova Scotia Power	NPCC-Maritimes	Y	Y	N	INT	300,000	412	Hurricane Juan	on 9/28/2003 at 23:58 ADT, Hurricane Juan caused widespread customers outages through the Halifax metropolitan area of Northeastern Nova Scotia. A total of 300,000 customers were affected by these outages.	Y	Y		Y	24,301
10/9/2003 14:52	0.6	North Western Energy	WECC-NWPP	Y	N	N	UO	0	N/A	Cause unknown	On 10/09/2003 at 14:24 MDT, multiple generating units were removed from service by system protection upon the loss of two high voltage transmission lines being removed from service by system protection. Cause of the line trips is unknown. Approximately 1800 MW of generation was tripped. No customers were affected as a result of this disturbance.	N	N	No FIRM demand interruption reported	Y	
10/26/2003 1:44	0.3	San Diego Gas & Electric Co.	WECC-CAMX	Y	Y	N	INT	90,000	N/A	Brush fires	On October 26, 2003 starting at about 0144, system protection removed from service several high voltage transmission lines due to a wide-area brush fire. Because of the numerous line trips, several substations were deenergized. As a result of this event, approximately 90,000 electric customers were without service. Some customers were without electric service for several days due to the extensive damage caused by the brush fire.	N	Y		Y	
11/13/2003 7:30	23.0	Niagara Mohawk	NPCC-NYISO	Y	Y	N	INT	50,280	180	Weather - high winds	On November 13, 2003 at about 0730, high winds across most of New York state caused scattered customer outages due to multiple transmission and distribution lines tripping. About 50,280 customers were affected by this wind storm. Winds speeds were reported between 55-70 MPH.	Y	Y		Y	2,774
11/13/2003 13:40	26.0	Dominion - Virginia Power and North Carolina Power	SERC	Y	Y	N	INT	67,000	300	Weather - high winds	During the period beginning on November 13, 2003 at 13:40 to November 14, 2003 at approximately 15:41, high winds through areas of northern Virginia caused the loss of electric service to approximately 67,000 customers due to distribution outages.	Y	Y		Y	5,229
12/1/2003 18:21	1.8	ISO-New England	NPCC-ISO-NE	Y	Y	N	INT	300,000	630	Off-normal operation	Predisturbance: During the morning on December 1, 2003, one of three high voltage transmission lines feeding into southeastern area of a control area was manually removed from service on the request of the local fire department, who was fighting a brush fire near the transmission line. A second high voltage transmission line was already removed from service on schedule maintenance. This altered the area configuration by leaving only two high voltage transmission lines feeding into the southeastern area of the control area. Disturbance: At 1813 EST on December 1, 2003, a power plant operator manually removed from service a generating unit because of a fire in a flue duct. The removal of this generating unit opened the station ring bus, which was in an abnormal configuration due to another high voltage transmission line being removed from service manually earlier in the day. At 1821, system protection removed from service the last high voltage transmission line feeding into the southeastern area of the control area causing the electric service interruptions to approximately 300,000 customers. The estimated customer load lost was 630 MW. By 2011 EST, the control area had restored the transmission system and all customer loads.	Y	Y		Y	774
12/4/2003	96.0	Puget Sound Energy	WECC-NWPP	Y	N	N	INT	175,000	175	Weather - high winds	During the early morning hours of December 4, 2003, severe weather conditions caused high winds throughout an area near off the northwestern portion of the Pacific Ocean. The high winds caused widespread distribution outages that affected approximately 175,000 electric customers. Restoration efforts will take two to three days to complete.	Y	Y		Y	11,256
12/4/2003 22:15	4.8	Wisconsin Electric Power Company	MAIN	Y	Y	Y	INT	36,000	500	Cause unknown	On December 4, 2003 starting at about 2215, system protection removed from service several high voltage transmission lines, which caused severe overloading. Due to the overloading, several additional high voltage transmission lines were removed from service by system protection. As a result of this event, about 440 MW of area generation was removed from service by system protection due to frequency swings. In addition, electric service to about 36,000 customers was interrupted. All electric service was restored by 0305 on December 5, 2003. The initial cause of this event is unknown.	Y	Y		Y	1,619
12/5/2003 4:49	0.4	City of Homestead	FRCC	Y	N	N	INT	16,500	27	Equipment failure and system protection misoperation	On December 5, 2003 at 0449 EST, system protection removed from service a high voltage transmission line due to equipment failure. At the same time, system protection removed from service a second high voltage transmission line due to breaker failure, which caused the opening of two transformers. This caused the loss of approximately 22 MW of customer loads. Approximately 16,500 customers lost electric service as a result of this event.	Y	Y		Y	8

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12/22/2003 7:05	11.1	The IMO	NPCC-Ontario	N	Y	N	UO	0	N/A	Equipment failure	An existing high voltage circuit breaker was replaced because it was over dutied. Prior to energization, the new breaker was assembled and gas filled per the manufacturer's specification and was run through all required tests. All tests were acceptable. At some point prior to the switching that day, the bus differential protection was removed in preparation for the energization of the breaker. Removal of the bus differential protection was not part of the switching order. The open breaker was successfully energized from the line side disconnect switches. With the breaker still in the open position, the breaker failed catastrophically when the bus side disconnect switches were closed. The failure started as a phase to ground fault. The 230 kV lines terminated at the substation with the failed breaker all tripped to clear the fault. One 230 kV line overtripped. Several 115 kV and 34.5 kV lines also tripped to clear the fault or responded to heavy loads that resulted from the area 230 kV line trippings	N	N	No FIRM demand interruption reported	Y	
12/23/2003 21:08	1.0	FirstEnergy - Jersey Central P&L	MAAC	Y	Y	N	UO	80,000	N/A	Human error	On December 23, 2003 at about 2108, system protection inadvertently removed from service several high voltage transmission lines during the routine restoration of a circuit breaker. As a result of this incident electric service to approximately 80,000 customers was interrupted. All customer services was restored within one hour.	N	N	No FIRM demand interruption reported	Y	
12/26/2003 1:12	5.8	HydroQuebec TransEnergie	NPCC-HQ	N	Y	N	INT	10	630	Weather	On December 26, 2003 at about 0112 EST, system protection removed from a high voltage transmission line due to severe weather. At 0136, the line was restored to service. At 0225, system protection again removed this high voltage transmission line from service. At 0703, the line was restored to service after an inspection. During these events, about 630 MW of firm industrial customer load was interrupted.	Y	Y		Y	2,469
1/8/2004 15:00	52.0	Niagara Mohawk, National Grid - New York	NPCC-NYISO	Y	Y	N	PA	18,600	100	Public Appeal	From about 15:00 EST on 1/8/2004 to about 19:00 EST on 1/10/2004 a utility company made public appeals for electric customers to reduce loads due to forecasted low temperatures of -30 degrees Fahrenheit in upper New York State.	N	N	Public Appeal	Y	3,484
1/11/2004 8:48	1.5	Western Area Power Administration, Loveland; Tri-State Generation and Transmission; PacifiCorp, Public Service Company of Colorado, Platte River Power Authority, and Cheyenne Light, Fuel and Power	WECC-RMPA	Y	N	N	UO	N/A	96	System Protection malfunction	On 1/11/2004 at about 08:48 MST, system protection removed from service three high voltage transmission lines due to a fault on a distribution bus that failed to clear properly. At about 09:00 MST, system protection removed from service another high voltage transmission line. At about 09:01, system protection removed from service a fifth high voltage transmission line. The five transmission lines emanated from the same substation. As a result of this event, approximately 96 MW of customer load was lost. In addition, a single wind generator carrying about 1.5 MW was removed from service. By 10:16 all transmission lines were returned to normal and all customer loads restored. The initial fault on the distribution bus was caused by an animal contact. The fault failed to properly clear by system protection and persisted for 15-minutes.	Y	Y		Y	96
1/23/2004 15:00	45.0	Niagara Mohawk, National Grid USA	NPCC-NYISO	Y	Y	N	PA	18,600	100	Public Appeal	From about 15:00 EST on 1/23/2004 to about 12:00 EST on 1/25/2004 a utility company made public appeals for electric customers to reduce loads due to forecasted low temperatures of -30 degrees Fahrenheit in upper New York State.	N	N	Public Appeal	Y	3,015
1/26/2004 7:30	3.0	Niagara Mohawk, National Grid USA	NPCC-NYISO	Y	Y	N	VR	18,600	100	Voltage Reduction	From about 0730 to 10:30 EST on 1/26/2004 to about 19:00 EST, a utility company implemented a 5% voltage reduction to reduce electric demand due to area temperatures that were much lower than originally forecasted. The voltage reduction was terminated at 10:30 EST and no further actions were required.	N	N	Voltage reduction	Y	201
1/26/2004 10:00	98.0	South Carolina Electric and Gas	SERC	Y	N	N	INT	150,000	700	Weather - ice storm	At about 1000 on January 26, 2004 a severe winter storm caused icing conditions that led to the loss of 500 to 700 MW of electric customer load. Service to approximately 150,000 electric customers was interrupted by this storm. All service to electric customers had been restored by 1200 EST on January 30, 20004.	Y	Y		Y	45,962
1/26/2004 14:00	34.0	Southern Company	SERC-Southern	Y	N	N	INT	30,689	150	Weather - ice storm	On 1/26/2004 at about 14:00 EST, a winter storm in North and Central Georgia caused severe icing on trees and power lines, which resulted in the loss of about 150 MW of electric customer load. Service to approximately 30,689 electric customers was interrupted by this this storm. (Need final restoration times)	Y	Y		Y	3,419
1/26/2004 16:00	80.0	Progress Energy - Carolinas, Carolina Power & Light	SERC	Y	N	N	INT	92,000	475	Weather - ice storm	On 1/26/2004 at about 16:04, a severe winter ice storm, in Central, Southern, and Eastern parts of North and South Carolina, caused the loss of about 475 MW of electric customer load. Service to approximately 92,000 electric customers was interrupted by this this storm. Restoration in the hardest hit areas is expected to take several days. (Need restoration times)	Y	Y		Y	25,460
1/28/2004 13:09	0.1	PJM Interconnection, LLC	MAAC	Y	Y	N	INT	65,000	300	Weather - icing	On 1/28/04 at about 13:09 EST, system protection removed from service two high voltage transmission lines as a result of galloping conductors, which was due to ice buildup and high winds. Service to approximately 65,000 electric customers was interrupted by this storm. All transmission lines were returned to service by 13:15 EST. Electric service to all customers was restored by 2048 EST.	Y	Y		Y	20
2/14/2004 20:00	40.0	Niagara Mohawk - National Grid U.S.	NPCC-NYISO	Y	Y	N	PA	18,600	30	Public Appeal	On February 14, 2004 at 20:00 EST, Niagara Mohawk initiated a public appeal to customers to reduce electric use due to inadequate electric resourced to serve load. The public appeal was terminated at 12:00 on 2/16/04.	N	N	Public Appeal	Y	804
2/26/2004 0:00	1.5	Southern Company	SERC-Southern	Y	N	N	INT	61,284	10	Weather - high winds and thunder	On February 26, 2004 at about 0000, high winds and severe thunder storms caused widespread interruptions to the electric service of approximately 61,284 customers. (Need final restore time)	Y	Y		Y	10

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2/26/2004 23:22	9.2	Alberta Electric Sysetm Operator	WECC-NWPP	N	N	N	UO	N/A	180	Weather - Fog and hoarfrost	On February 26, 2004 at 2322 MST, system protection removed from service several high voltage transmission lines, a section of bus and a step-down transformer at a transmission substation. In addition, system protection removed from service a high voltage transmission tie line separating the affected system from the Western Interconnection. In addition, system protection removed from service various generating units totally 118 MW of generation and 180 MW of firm customer loads due to voltage deviations. The cause of these events was high fog and hoarfrost in the region. At 2344, the islanded system was resynchronized with the Interconnection. At about 0836 MST on February 27, 2004, all generating units and customer electric service had been restored.	Y	Y		Y	1,114
3/4/2004 15:06	2.2	ERCOT ISO	ERCOT	Y	Y	N	INT	41,000	300	Weather - high winds, possible tornado	On March 4, 2004 at 15:06 CST, system protection removed from service three sets of high voltage double circuits due to high winds and a possible tornado. Each set of double circuits was importing into a metropolitan area approximately 250 MW. At about 16:33 system protection removed from service two additional high voltage double circuits that were importing approximately 1155 MW into the same metropolitan area. As a result of these events the electric service to approximately 41,000 customers was interrupted. (Need restoration times	Y	N	No FIRM demand interruption reported	Y	432
3/8/2004 17:50	0.8	California ISO, Southern California Edison Company	WECC-CAMX	Y	Y	N	INT	70,000	300	Human Error	At about 1750 PST on March 8, 2004, a control area requested that a local transmission operator shed approximately 160 MW of interruptible load and 300 MW of firm customer demand to decrease loading on an internal transmission path after de-dispatch of generation failed to alleviate the overload. All customer demand, both firm and interruptible, were restored by 1838 PST. The cause of this incident was do to a forecasting error and higher than expected ambient temperatures in the southern portion of the control area.	Y	Y		Y	161
3/17/2004 13:27	0.7	El Paso Electric Company	WECC-AZNMSNV	Y	N	N	INT	100,000	300	Equipment failure	At about 1327 MST on March 17, 2004, a step-up transformer on a generating unit failed. This caused several high voltage transmission lines to be removed from service by system protection in the underlying transmission system. As a result of this incident, the local undervoltage relay scheme operated shedding approximately 300 MW of firm load. This caused the loss of electric service to about 100,000 customers. In addition, 60 MW of local generation and 10 MW of generation in a neighboring system was removed from service by system protection. All electric service and transmission lines were restored to service by 14:06 MST.	Y	Y		Y	131
3/18/2004 9:18	4.1	British Columbia Transmission Corporation	WECC-NWPP	N	N	N	INT	74,000	78	Equipment failure	At about 0918 PST on March 18, 2004, system protection removed from service two high voltage transmission lines due to a tower failure caused by high winds. Prior to this event, another high voltage transmission line had been manually removed from service due to a broken cross arm because of the high winds. This sequence of events caused the loss of electric service to about 74,000 customers (78 MW of firm load.). By 1325 PST, all customer electric service had been restored.	Y	Y		Y	215
3/23/2004 17:37	1.8	Tri-State Generation and Transmission Assocation, Western Area Power Administration - CM	WECC-RMPA	Y	N	N	INT	N/A	135	Misoperation	At about 17:37 MST on March 23, 2004, system protection removed from service an existing high voltage step-down transformer while testing was in progress on a new high voltage transformer within the same substation. This incident cased system protection to remove from service two high voltage transmission lines emanating from this substation. As a result of the initial incident, about 30 MW of firm customer demand was lost. At about 17:52 system protection removed from service another high voltage transmission line in the area due to overload. As a result an additional 105 MW of firm customer demand was lost. All customer demand was restored by 19:26 MST. In addition to the firm customer demand lost, about 10 MW of local generation was removed from service by system protection.	Y	Y		Y	164
4/2/2004 13:17	3.9	PJM Interconnection, LLC, OVEC and AEP	ECAR	Y	Y	N	UO	0	N/A	Third party contact	At 13:17 on April 2, 2004, system protection removed from service multiple high voltage transmission lines from service after a construction crane contacted one of the transmission lines adjacent to a substation. In addition, system protection removed a single generating unit carrying 210 MW. There were no customers affected by this event. (Need final restoration time for lines)	N	N	No FIRM demand interruption reported	Y	
4/11/2004 11:49	1.0	Entergy	SERC-Entergy	Y	N	N	UO	0	N/A	Computer trouble	At about 1149 CDT on April 11, 2004, a Control Area's SCADA computer failed and did not transfer to the backup source. This disabled a portion of the control area's automatic load shedding scheme. There were no electric customers affected by this incident. By 1248 CDT, the SCADA computer had been fully restored.	N	N	No FIRM demand interruption reported	Y	
4/12/2004 5:30	42.5	Florida Power and Light	FRCC	Y	N	N	INT	179,000	250	Weather - high winds and lightning	At about 0530 EDT on April 12, 2004, a series of thunderstorms with high winds gusting between 50 to 60 mph, caused a large number of distribution interruptions because of tree contacts, wires down and other problems. In addition, there were reports of possible tornado activity associated with the storm front. The storm moved west to east across the utility's service territory. There were approximately 179,000 electric customers affected by this storm, with a maximum of 90,000 customers without power at any one time. At about 03:00 EDT on April 13, 2004, a second wave of strong thunderstorm activity moved across the utility's service territory, causing additional distribution interruptions. All customer electric service was restored by 2400 on April 13, 2004	Y	Y		Y	7,116

MidwestISO
Energizing the Heartland

2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
4/28/2004 9:27	1.0	New Brunswick Power, Maritime Electric Company Ltd.	NPCC-Maritimes	Y	Y	N	INT	97,500	245	Conductor sagging	On April 28, 2004 at 0927 ADT, a high voltage transmission line sagged into a lower voltage under built transmission line, causing system protection to remove both transmission lines from service. This caused the interruption to electric service of 22,000 customers. In addition, because of a temporary reconfiguration of the transmission system, this incident also interrupted another 75,500 electric customers because of a single feed into another portion of the affected system. By 1026 ADT, all transmission lines and electric service to customers had been restored.	Y	Y		Y	161
5/17/2004 9:39	0.9	HydroQuebec TransEnergie	NPCC-Quebec	N	Y	N	INT	0	N/A	Inadvertant tripping	On Monday May 17, 2004 at about 0939 EDT, system protection inadvertently removed from service a high voltage step-up transformer and two generating units causing the loss of about 900 MW of generation. By 1032 EDT, the transformer and both generating units were restored to service. There was no customer affected by this incident. The cause of the incident is unknown.	N	N	No FIRM demand interruption reported	Y	
5/19/2004 12:01	0.1	HydroQuebec TransEnergie	NPCC-Quebec	N	Y	N	INT	0	N/A	System Protection	On May 19, 2004 at about 1201 EDT, system protection removed from service a high voltage transformer. As a result of this incident, system protection subsequently removed from service a high voltage transmission line and three generating units. This caused the loss of about 750 MW of generation. There were no customers affected by this incident. The cause of this incident is unknown.	N	N	No FIRM demand interruption reported	Y	
5/22/2004 18:57	14.3	Nebraska Public Power District	MAPP	Y	Y	Y	INT	N/A	40	Severe weather - thunderstorm and tornados	Between 1857 and 2046 CDT on May 22, 2004, system protection removed from service several high voltage transmission lines due to severe thunderstorms and tornadoes throughout the service area of a public power district. In addition, this event caused the interruption to approximately 40 MW of firm electric customer load and the tripping of about 145 MW of area generation. There was extensive damage to several transmission lines and tower structures throughout the area affected. By 0917 CDT on May 23, 2004, most of the transmission system was normal, service to electric all customers, and all generating units had been restored. There remains out of service some transmission lines because of the extensive damage.	Y	Y		Y	384
5/28/2004 12:00	84.0	Seminole Electric Coorperative, Inc.	FRCC	Y	N	N	PA	50,000	N/A	Inadequate resources	On May 28, 2004 at 12:00 EDT, a utility company made a public appeal to its electric customers to conserve energy due to a generation deficiency. On June 1, 2004 at about 2400 EDT, the public appeals were terminated because the weather had moderated and additional generating resources became available within the affected area.	N	N	Public Appeal	Y	
5/28/2004 16:21	0.2	Southern Company	SERC-Southern	Y	N	N	UO	0	N/A	Cyber attack	At about 1621 EDT on May 28, 2004, a cyber attack disrupted the OASIS Transmission Reservation system At 1636, OASIS was normal. This event did not cause any distruption to service.	N	N	No FIRM demand interruption reported	Y	
6/1/2004 17:00	91.0	TXU Electric Delivery	ERCOT	Y	Y	N	INT	500,000	1,900	Weather - severe lightning and high winds	On June 1, 2004 at about 1700 CDT, a severe storm, with lightning, heavy rain, hail and wind gusts of up to 80 mph, crossed a large metropolitan area in Texas. This storm caused severe damage to the electric system with numerous poles and wires down. This event caused interruption to the electric service of about 500,000 customers. Restoration efforts were assisted by neighboring utilities from as far as 750 miles from affected area. As of about 1100 CDT on June 2, 2004, some 350,000 electric customers remained without service.	Y	Y		Y	115,843
6/12/2004 17:37	0.1	Lincoln Electric System	MAPP	Y	Y	Y	INT	120,212	428	Weather	On June 12, 2004 at about 1712 CDT, a severe storm, with possible tornados, caused extensive damage thought out the service area of a utility in Nebraska. Because of damage from a previous storm, there were widespread electric customer outages because of damage to both the transmission and distribution systems. About 120, 212 electric customers were interupted because of this storm. Repairs to the transmission and distribution system will take several days to complete.	Y	Y		Y	19
6/14/2004 7:41	0.8	Arizona Pulic Service Company, Salt River Project, Western Area Power Administration - DSW Area, AESO, Tucson Electric Power, Public Service of New Mexico, California Independent System Operator	WECC-AZNMSNV	Y	N	N	INT	41,000	492	Equipment failure, system protection malfunction	On June 14, 2004 at 0741 MST, system protection failed to properly clear a fault on a high voltage transmission line by primary and breaker failure relaying. Subsequently, the backup relaying failed, which caused the remote tripping of several high voltage transmission lines. In addition to the various transmission lines that tripped, several generating units were also removed from service by system protection. Approximately 4589 MW of generation was lost. Underfrequency load shedding of 492 MW occurred, which interrupted the electric service to about 41,000 customers. Much of the underfrequency load shedding occurred in nearby systems. On the disturbance, the Interconnection's frequency deviated from 59.999 Hz to 59.498 Hz and recovered to 59.925 Hz. The Interconnection's frequency returned to normal by 0757. At about 0750, the regional Reliability Coordinator directed the affected system to manually shed firm load to recover its Area Control Error (ACE). Even though the affected system entered 500 MW into its load shedding program, the program failed to operate. However, about 200 MW of load reduction occurred because of the loss of induction motor loads within the affected system. The affected system received up to 800 Mw of emergency assistance from an adjacent control area.	Y	Y		Y	247

2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
6/23/2004 17:35	1.6	Idaho Power Company	WECC-RMPA	Y	N	N	UO	35,000	157	Unknown	On June 23, 2004 at about 1735 MDT, a utility company manually shed about 157 MW of firm customer load after system protection removed from service a high voltage transmission line and about 96 MW of local generation. Just before this occurred, another high voltage transmission line had been removed from service by system protection. The utility company shed load to maintain transmission security limits and to restore operating reserves. At 1752 MDT, local generation was restored. By 1910 MDT, restored all firm customer loads. The cause of this incident is unknown.	Y	Y		Y	167
6/23/2004 19:00	1.0	Southern Company	SERC-Southern	Y	N	N	INT	50,595	50	Weather - Severe thunder storm	At about 1700 CDT, on June 23, 2004, a series of severe thunder storms caused the interruption of about 50,595 electric customers due to numerous distribution outages. Most of the customers affected were restored by 2000 CDT.	Y	Y		Y	34
7/4/2004 18:59	0.8	Arizona Public Service Company	WECC-AZNMSNV	Y	N	N	UO	0	N/A	Equipment failure	On July 4, 2004 at 1859 MST, system protection removed from service a high voltage step-down transformer due to an internal fault and resulting fire. As the smoke from the fire spread, three adjacent high voltage transformers were also removed from service by system protection. A high voltage transmission line, associated with one of these transformers, was also removed from service. No generation or electric service to customers was affected. At 1945, a high voltage transmission line was manually removed from service to facilitate fire control activities on the affected transformer. When this high voltage line was de-energized, two generating units were removed from service by system protection. However, there was no loss of electric service to any customers.	N	N	No FIRM demand interruption reported	Y	
7/5/2004 17:18	0.6	Hydro-Quebec Transenergie	NPCC-Quebec	N	Y	N	UO	175,000	1,778	Maintenance error	On July 5, 2004 at 1718 EDT, system protection removed from service several generating units by a Special Protection Scheme (SPS) when a false signal was injected into the dc portion of a protection relay during routine maintenance. This resulted in about 3,000 MW of generation being rejected and automatic load shedding of 1,500 MW being initiated. In addition to the automatic load shedding, another 375 MW of load was shed by underfrequency relaying. Because of this event, 175,000 electric customers were interrupted. All electric customers were restored by 1755.	Y	Y		Y	735
7/7/2004 13:30	21.2	Dominion - Virginia Power and North Carolina Power	SERC-VACAR	Y	Y	N	INT	8,110	120	Weather - severe thunderstorms	On July 7, 2004 at about 1330 EDT, severe thunderstorms moved across the service areas of a utility company causing widespread electric customer interruptions on the distribution system. About 88,110 electric customers were affected. By 1045, on July 8, 2004 EDT, most electric customers had been restored.	Y	Y		Y	1,708
7/13/2004 14:05	3.2	City of Tallahassee	FRCC	Y	N	N	INT	42,122	283	System Protection	On July 13, 2004 at 1405 EDT, system protection removed from service a single generating unit due to air/fuel runback. About 6 seconds later, a second generating unit at the same plant was removed from service by system protection. In addition, a non-company generating unit (being rented) tripped while carrying 52 MW. The total generation lost within the control area was 368 MW. The only remaining generation within the boundaries of this control area was a gas-turbine, loaded at about 10 MW. Earlier in the day, at about 1334, another generating unit carrying 235 MW had been removed from service by system protection due to exciter trouble. The loss of this generation, and due to tie-line loadings, the control area's voltage was now low. While system operators were calling for operating reserves and purchasing additional imports, about 283 MW of firm customer load was manually shed to stabilize the transmission voltages. At about 1647, all generating units had been restored. At about 1715, all customer loads had been restored. A about 42,122 electric customers were without electric service starting at about 1414. In addition, two interruptible customers were shed	Y	Y		Y	600
7/20/2004 2:30	6.8	Arizona Public Service Company	WECC-AZNMSNV	Y	N	N	INT	50,000	250	Equipment failure	Before this incident occurred, a prior outage at a different facility required modifications in the system configuration, which resulted in the facility where this incident occurred to be on a single source of power. On July 20, 2004 at 0230, system protection removed from service a high voltage step down transformer. Because of the system configuration, due to a previous incident, this caused the only power source into this substation to open. As a result, this de-energized the entire substation. The cause of the incident was a failed high-side transformer bushing. About 250 MW of firm customer load was interrupted. This interrupted the electric service to about 50,000 customers. All customer loads were restored by 0918. The faulted transformer was restored to service with a spare transformer.	Y	Y		Y	1,139
7/21/2004 17:30	25.5	Commonwealth Edison	MAIN	Y	Y	N	INT	200,000	200	Severe weather - thunderstorm and high winds	On July 21, 2004 at about 17:30 a severe thunderstorm with high winds, gusting to about 60 mph, moved through the service area causing damage to the distribution system. This storm continued through on July 22, 2004. The electric service to about 200,000 customers was interrupted because of the damage caused by this storm. The majority of the customers interrupted had been restored by 1900 CDT on July 22, 2004.	Y	Y		Y	3,417
7/24/2004 15:45	30.2	Entergy Transmission company	SERC-Entergy	Y	N	N	PA	N/A	N/A	Public Apeal	On July 24, 2004 at 1545 EDT, a utility company initiated public appeals for the conservation of electric useage due to transmission constraints across a critical transmission path. Generation re-dispatch and use of the transmission line load relief procedure was also used to mitigate this constraint. At 2200 EDT, the public appeal was cancelled. No firm customer demand was interrupted because of the constraint.	N	N	Public Appeal	Y	

The Improved Reliability benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
7/25/2004 22:00	1.0	Southern Company	SERC-Southern	Y	N	N	INT	61,004	61	Weather	On July 25, 2004 at 22:00 EDT, about 61,004 electric customers lost service due to the loss of a high voltage transmission line as a result of a storm. At 2300 EDT, the transmission line was returned to service and all customer loads restored.	Y	Y		Y	41
8/1/2004 11:00	9.0	Entergy Transmission, GSU Texas	SPP	Y	Y	N	PA	0	N/A	Public appeal	On August 1, 2004 from 11:00 to 20:00 EDT, a utility company issued public appeals for energy conservation due to the loss of generating capacity. No firm customer loads were interrupted. The utility did order its interruptable customers off line from 12:00 to 20:00 EDT.	N	N	Public Appeal	Y	
8/2/2004 10:00	12.0	Entergy Energy Services and GSU Texas	SPP	Y	Y	N	PA	0	N/A	Public appeals	On August 2, 2004 from 11:00 to 20:00 EDT, a utility company issued public appeals for energy conservation due to the loss of generating capacity. No firm customer loads were interrupted. The utility did order its interruptable customers off line from 12:00 to 22:00 EDT.	N	N	Public Appeal	Y	
8/3/2004 10:00	N/A	Entergy Energy Services and GSU - Texas	SPP	Y	Y	N	PA	0	N/A	Public appeal	On August 3, 2004 at 10:00 CDT, a utility issued a public appeals due to the unplanned generator outages and high loads. No firm customers load was interrupted.	N	N	Public Appeal	Y	
8/4/2004 12:46	1.1	California ISO, Southern California Edison	WECC-CAMX	Y	Y	N	INT	171,600	480	Equipment failure	On August 4, 2004 at 1246 PDT, system protection removed from service a high voltage substation bus due to the internal failure of a circuit breaker. In addition, two high voltage transmission lines were also removed from service by system protection. The substation was in an off-normal configuration where the other bus was de-energized for station washing. This incident caused the dropping of about 480 MW of firm electric customer load, which affected about 171,600 electric customers. By 1350, the electric service had been restored to all customers. By 1357, both high voltage transmission lines had been restored.	Y	Y		Y	343
8/10/2004 14:20	3.9	Western Area Power Administration - Lower Colorado, Arizona Public Service, and Salt River Project	WECC-AZNMSNV	Y	N	N	UO	3	40	Brush Fire	On August 10, 2004 at 1420 MST, system protection removed from service a high voltage transmission line due to a nearby fire. At about the same time, a two high voltage step down transformers were also removed from service by system protection due to high overcurrent. Because of this event, the bus voltage dropped to about 0.927 per unit. At 1422, an additional high voltage transmission line was manually removed from service due to the fire. This caused the bus voltage to decline further to 0.900 per unit. Because of the declining voltages, about 40 MW of firm customer load was manually shed. Area voltages improved as a result of shedding load, however, did not fully recover. The control area system operator attempted to energize one of the high voltage step down transformers, but the transformer relayed again by what was believed to be high inrush currents. The control area system operator was eventually able to return both high voltage transformers to service. By 1815, all transmission lines were back in service. The shedding of 40 MW of firm customer load involved three customers only.	Y	Y		Y	105
8/13/2004 13:30	N/A	Seminole Electric Cooperative, Inc.	FRCC	Y	N	N	INT	200,000	700	Severe weather - hurricane Charley	On Augsut 13, 2004 at about 13:30 Hurricane Charley hit much of the western coast of Florida causing severe damage to the transmission and distrubition infrastructure. About 200,000 electric customers were interrupted.	N	Y		N	
8/13/2004 15:00	249.0	Florida Power & Light	FRCC	Y	N	N	INT	400,000	1,400	Severe weather - Hurricane Charley	On August 13, 2004 at about 1500 EDT, Hurricane Charley made landfall on the west coast of Florida. The wind speeds were up to 145 mph. This caused major damage to the transmission and distribution infrastructure. By 1530, about 50,000 electric customers were without power. As the storm continued, additional transmission and distribution feeders tripped. By 1630, about 290,000 electric customers were without power. By 1945, the winds started to subside to a level where an assessment of the damage could begin. As a result of this storm a total of about 400,000 electric customers were left without power. Complete restoration is expected to take approximately two to three weeks in the west coast area with most electric services returned by 8/25/04 in the northern area.	Y	Y		N	233,562
8/14/2004 13:00	58.0	Progress Energy - Carolinas, Carolina Power and Light	SERC-VACAR	Y	N	N	INT	94,000	500	Severe weather - hurrican Charley	On August 14, 2004 at about 13:00 Hurricane Charley hit portions of Central and Eastern North Carolina and Eastern South Carolina causing wide-spread electric customer outages. At the peak of the storm more than 94,000 electric customers were interrupted. On 8/16/04 at about 12:00 all electric customers had been restored.	Y	Y		N	19,430
8/18/2004 9:59	0.1	TXU Electric Delivery	ERCOT	Y	Y	N	UO	2	178	Human error		Y	Y		Y	18
8/20/2004 15:27	8.5	ISO New England	NPCC-ISO-NE	Y	Y	N	VR	27,388	N/A	Weather - lightning	On August 20, 2004 at about 1531 EDT, system protection removed from service a high voltage transmission line due to a lightning strike. This resulted in about 900 MW of generation runback. As a result of the generation deficiency in the area, the utility implemented a 5% voltage reduction that affected about 27,388 customers.	N	N	Voltage reduction	Y	
8/29/2004 9:52	62.1	South Carolina Electric and Gas Company	SERC	Y	N	N	INT	125,000	450	Weather - Tropical Storm Gaston	On August 29, 2004 at about 09:52 EDT, Tropical storm Gaston passed through South Carolina. Widespread disturbution outages were caused by this tropical storm with an estimate of about 125,000 electric customers being without power. Restoration efforts continued with the last eleictric customers being restored by 9/1/2004.	Y	Y		Y	18,733

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Research Review

FEBRUARY 2010

TOO MUCH BETA—WHY HEDGED EQUITY NOW

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Since the equity market lows of March 9, 2009, the S&P 500 Index returned 66.8% through February 28, 2010. Over the last two years, investors experienced some of the most dramatic swings in global equity market history. These movements were largely the result of the standard greed/fear bubble scenario that has played out since the first tulip bulb was traded with the corresponding credit crises fueling the fire. Now that the markets have busted and boomed again, we are left with an equity market that has largely been driven by macro factors for a sustained period of time and appears to be fairly valued globally. A better environment for opportunistic active managers generally follows periods such as these. We also believe the classic long-biased hedged equity fund provides the best structure for active managers to add value. FEG has recommended a strategic allocation to hedged equity for some time. Given market conditions today, we believe this structure also presents an attractive tactical opportunity. In this focus topic, we discuss the structural benefits of hedged equity and its placement and role in a portfolio. We then examine the historical benefits hedged equity provides a portfolio, and lastly evaluate why we recommend a tactical overweight now.

Structural Advantages of Hedged Equity

Hedged equity (also known as long/short hedge funds) is the name we are using to describe the long standing hedge fund strategy of investing in equities both long and short and with some amount of leverage. There are an infinite number of approaches to this strategy, and as with anything, making generalities is dangerous. There is a fairly typical philosophy that hedged equity investment managers we recommend follow, including:

- A focus on risk-adjusted returns
- Long-bias – most managers are typically 0-60% net long
- Moderate use of leverage – most managers are typically 80-180% gross invested
- Fundamental bias – focus on company research and analysis
- Hedge fund structure – the hedge fund structure allows for the most opportunistic investing

One of the most prominent reasons for the emergence of the hedged equity structure is the strong performance over the last 20 years. This has drawn investors to the strategy and resulted in the proliferation in the number of managers. We believe a key factor that allowed hedged equity to outperform the traditional benchmarks is the lack of constraints placed on them by investors, consultants, and regulators relative to the traditional investment managers. Traditional managers are typically constrained to long-only investments and by a benchmark that is constructed to capture a style or market capitalization category. Additionally, traditional managers must maintain daily liquidity, and have limits on leverage, the inability to short overvalued stocks, and the types of securities that are allowed. These constraints are structural mandates of the mutual fund industry that rose to prominence in the 1980s, as well as imposed constraints that have been placed on investment managers by the broader investment community. We will refer to the constrained mandate from this point forward as "long-only" in reference to what is likely the most significant constraint of this model. Long-only investment managers control the majority of investment capital and this has provided the opportunity for strategies that are less constrained to shine. This commentary is not a critique of long-only investing, as this strategy rightfully continues to account for the majority of capital invested. Standardization and acceptance of an idea, however, creates opportunities for the alternative.

The removal of constraints on equity managers has proven over time to provide talented investors a platform to generate risk-adjusted returns far in excess of long-only equity indices. This excess performance can be attributed to better "talent" and "tools." There has been a distinct trend over the last decade of talented investment professionals crossing over to the hedge fund industry from the traditional investment strategies. Some of the allure is due to the compensation that a "2% & 20%" model can afford, while others are attracted by the intellectual freedom of unconstrained investing. There is also a distinct difference in the tools available to talented investment managers. By loosening the constraints, hedged equity managers can make more significant bets while actively managing the unwanted risks of the portfolio. Over a full market cycle, there is no reason to believe talented managers with better tools should not outperform their more constrained brethren. A recent academic paper was published that supports this belief and concludes lighter regulation (i.e., more flexibility) and better alignment of interests are the reason for the outperformance of hedge funds.[1] In fact, since 1990 the HFRI Equity Hedge Index outperformed the S&P 500 Index and the MSCI AC World Index on both an absolute and risk-adjusted basis, as seen below.

January 1990 - January 2010

Annualized Statistical Analysis	ROR	Standard Deviation	Sharpe	Max Drawdown	Beta	Correlation R	R^2
HFRI Equity Hedge Index	14.1%	9.2%	0.95	(30.6%)			
S&P 500 Index	8.0%	15.0%	0.26	(50.9%)	0.44	0.71	0.50
MSCI AC World Index	5.9%	15.7%	0.13	(54.6%)	0.42	0.71	0.51

Source: Hedge Fund Research, Lipper

The construction of the HFRI (and other hedge fund) indices have certain weaknesses, but we believe the magnitude of the outperformance and lower volatility offset these construction issues.

Role

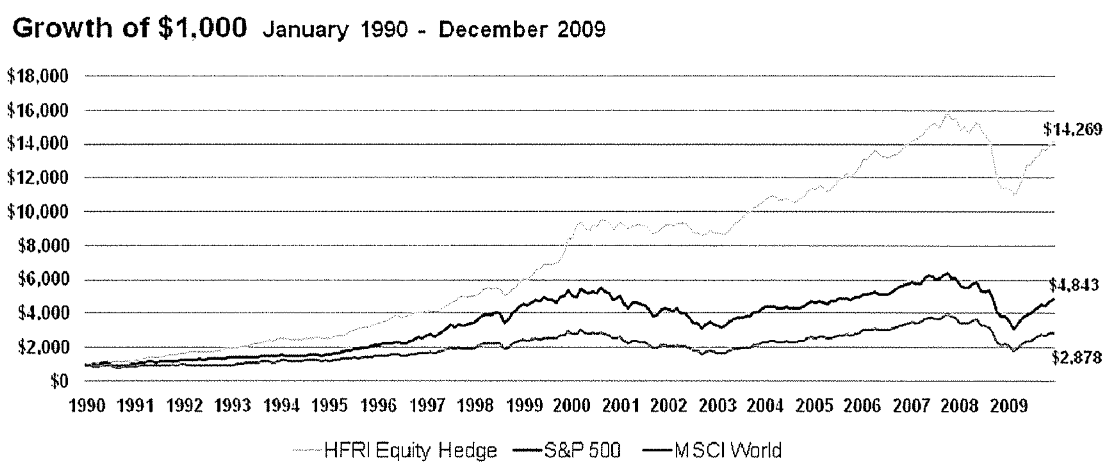
FEG does not believe hedge funds are an asset class, but rather, merely a structure to access and invest in different asset categories. We prefer to group managers by the underlying risk exposure. These four broad categories are Global Equities, Global Fixed Income and Credit, Real Assets, and Diversifying Strategies.

Asset Categories	Risk Premia	Role
Global Equity (stocks, private equity, long/short hedge funds)	Equity Risk Premium	Total Return
Global Fixed Income and Credit (bonds, bank loans, credit hedge funds)	Interest Rates and Credit	Equity Risk Mitigation
Real Assets (real estate, natural resources, commodities)	Inflation	Inflation Protection
Diversifying Strategies (absolute return hedge funds, trading strategies)	Active Management	Diversification

Hedge fund managers can be utilized to access all asset categories. Specifically, hedged equity managers fall under the Global Equity category, as the underlying risk exposure is equities.

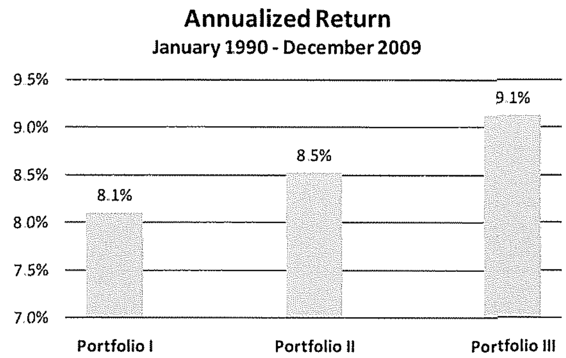
The primary role of hedged equity managers remains total return, as we expect returns similar to equity markets over a full market cycle. FEG expects that hedged equity managers, however, will have a lower beta than a traditional long-only equity manager due to the additional tools available to them. The inclusion of hedged equity should provide valuable diversification benefits to the equity portion of an investor's portfolio. As shown on the previous page, the beta for the HFRI Equity Hedge Index to the broader markets is approximately half of what we would expect from a long-only equity manager. Determining the size of the allocation depends on an investor's liquidity needs, acceptance of tracking error, and experience and comfort with alternative strategies.

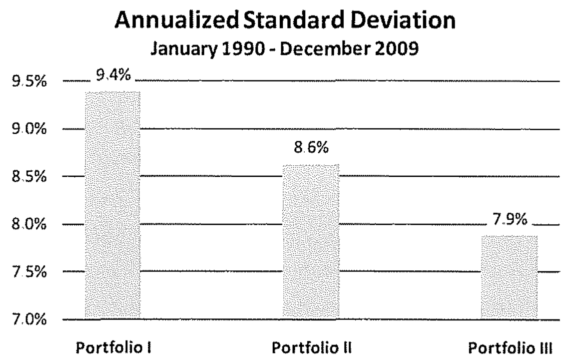
Portfolio Benefits

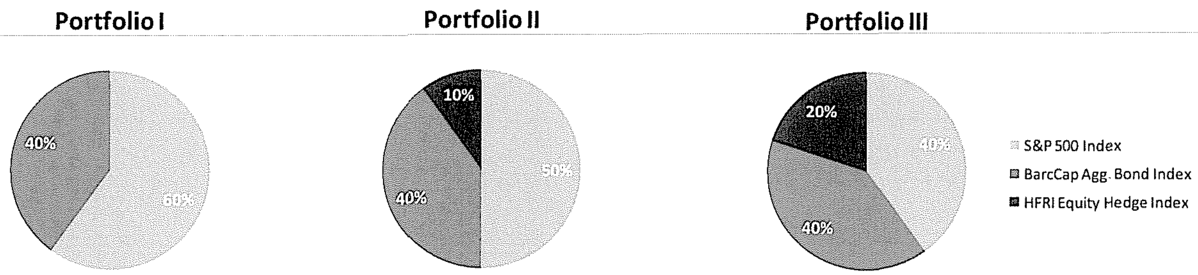


Source. Hedge Equity Research, Lipper

The following graph shows the growth of $1,000 for the HFRI Equity Hedge Index compared to the S&P 500 Index and the MSCI World Index since 1990. The graph illustrates the compounded growth of an investment in hedged equity far outpaced that of the long-only indexes.





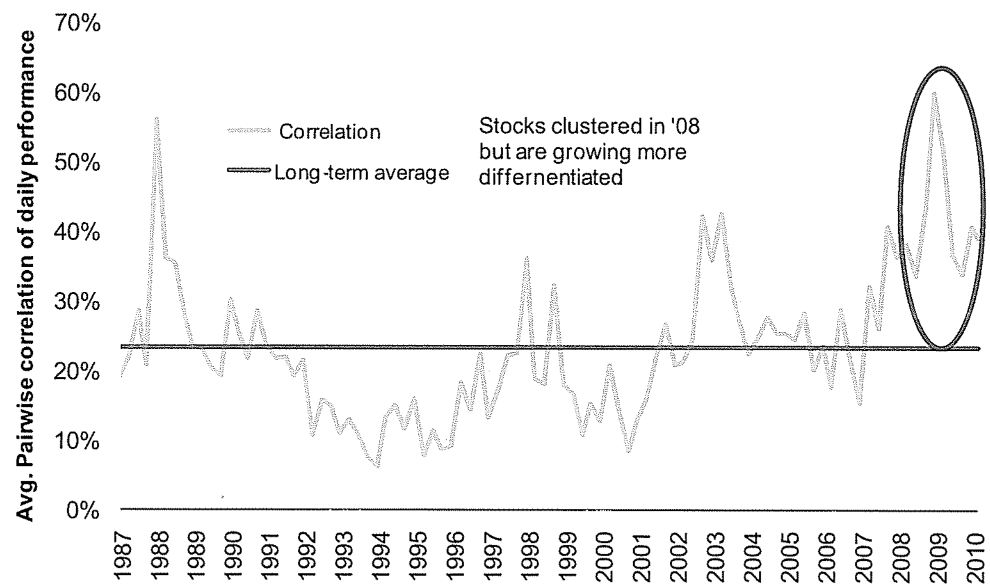


Source: Hedged Equity Research, Lipper

In examining historical portfolio simulations, re-allocating a portion of the long-only equity allocation to hedged equity would have resulted in significantly improved risk-adjusted returns. Each incremental addition of hedged equity increased the historical return and decreased the historical risk, as measured by standard deviation.
We believe the analysis is compelling, however, in taking a cautious approach we want to make sure the results are robust and not overly end-point sensitive. Therefore, we analyzed the returns to hedged equity versus the S&P 500 Index on a rolling three and five-year basis. Over 205 trailing three-year periods between 1990 and 2009, the HFRI Equity Hedge Index outperformed the S&P 500 Index 72% of the time. Over 181 trailing five-year periods between 1990 and 2009, the HFRI Equity Hedge Index outperformed the S&P 500 Index 81% of the time. On a risk-adjusted basis, as measured by the Sharpe Ratio, the HFRI Equity Hedge Index outperformed the S&P 500 Index 100% of the time on both a rolling three and five-year basis. This leads us to conclude that the strong risk reduction and return enhancement properties shown above are fairly robust and not endpoint sensitive.

Risks of Hedged Equity

We have focused on the benefits of investing in hedged equity, however, we must also acknowledge the risks. With no constraints, a hedged equity manager has the ability to utilize more tools in the construction of the portfolio. Those tools require a more sophisticated skill set in both portfolio and operational management than is required of long-only managers. These additional tools increase the opportunity for negative outcomes. For example, a stock purchased long can only go to zero, limiting an investor's downside. A stock sold short, however, can increase infinitely, resulting in unlimited loses. Other risks of short selling include the cost to borrow, crowded shorts, and short squeezes. Regulatory risk is also a concern. The SEC's ban on short selling financial stocks in September



Source: Bank of America Merrill Lynch

2008 is a perfect example. Without the ability to sell financial stocks short, hedged equity managers lost an extremely valuable tool, and as a result, may have had more risk in their portfolio than intended. The use of leverage can also increase the risk of hedged equity if not managed appropriately. Finally, liquidity is a concern for investors in any hedge fund structure. Although hedged equity is typically more liquid than other hedge fund strategies, hedged equity managers still have the ability to impose withdrawal restrictions on investors. This may result in limited liquidity when it is needed most.

Investors must be aware of the magnification of existing risks and introduction of new risks when investing in hedged equity strategies. Providing the investment manager with more tools means there must be more sophisticated and

ECONOMIC UPDATE

Christina M. Sunderman
Research Analyst

Markets are Surprised by Fed's Action

The Federal Reserve increased the discount rate by a quarter percentage point to 0.75% on February 18th to encourage banks to use the private market as a main source of funds. This increase does not necessarily have a direct effect on the Federal Funds rate, which determines the rate banks charge each other for overnight loans. In a normal market environment, however, the discount rate is typically one percentage point above the Fed Funds target rate, which currently is between 0-0.25%. The timing of this action was somewhat unexpected by the market, and can be viewed as a step forward in broadly raising interest rates, although the Fed firmly stated that the federal funds rate will stay at "exceptionally low levels for an extended period."[1]

Gross domestic product estimates for the fourth quarter of 2009 were revised upward to 5.9% from 5.7%, due primarily to positive contributions from private inventory investment, exports, personal consumption expenditures, and nonresidential fixed investment.[2] Additionally, the consumer price index (CPI), which measures a representative basket of goods and services, increased by 0.2% in January. The energy index within the CPI rose, namely due to an increase in the gasoline, fuel oil, and natural gas indexes, which were slightly offset by a decline in the electricity index.[3]

"Distressed homes sales represented a sizable portion of transaction activity in January, at approximately 38%, creating a downward influence on the median home price."

Housing Inventory Climbs

The housing market continued to face headwinds as sales of single-family homes fell in January to a seasonally adjusted annual rate of 309,000. This is a decrease of 11.2% from December 2009, and represents a new record low since the government began tracking this data in 1963.[4] Consequently, the housing supply edged up to 9.1 months of inventory in January compared to 8 months of inventory in December. Home prices continued to decline as the median sales price for new homes was $203,500, approximately 2.5% below year-over-year levels.[5] Distressed homes sales represented a sizable portion of transaction activity in January, at approximately 38%, creating a downward influence on the median home price.[6] Falling prices and slow transaction activity is further hampered by the approximately one-quarter of mortgages in the U.S. that are underwater (where homeowners owe more than their home is worth.)[7] This scenario creates difficultly in selling a house or refinancing a loan and continues to weigh on the market.

Personal Savings Rate Falls amid Pessimistic Sentiment

The Index of Consumer Sentiment was largely unchanged in February at 73.6, slightly down from 74.4 in January.[8] The current tough job market and the bleak outlook for income gains continued to present challenges to consumer spending, as consumer buying plans waned amid an uncertain future. Personal income edged up slightly by 0.1% in January; however, disposable personal income fell by 0.4% due to an increase in federal nonwithheld income taxes. While consumers remain concerned about future job prospects, savings rate trends did not support this pessimistic sentiment, as personal savings fell from 4.2% in December to 3.3% in January.[9]

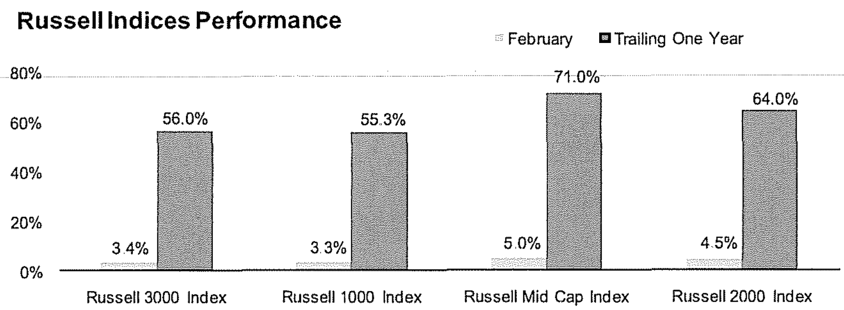
1 Gongloff, Mark, Tom Lauricella, and Min Zeng. *The Wall Street Journal Online*. "Fed Surprises Markets With an Increase in Bank Rate." 20 February 2010.
2 Bureau of Economic Analysis. "Gross Domestic Product: Fourth Quarter 2009 (Second Estimate). Information available from http://www.bea.gov. 26 February 2010.
3 Bureau of Labor Statistics. "Consumer Price Index – January 2010." Information available from http://www.bls.gov. 19 February 2010.
4 Murray, Sara. "New Home Sales Plunge to Record Low." The Wall Street Journal Online. 25 February 2010.
5 U.S. Department of Housing and Urban Development. "New Residential Sales in January 2010." Information available from http://www.census.gov/newhomesales. 24 February 2010.
6 The Wall Street Journal Online. "Existing-Home Sales Down in January but Higher than a Year ago; Prices Steady." Information available from http://www.wsj.com. 26 February 2010.
7 Nutting, Rex. "11.3 million homeowners underwater on mortgage." Information accessed from http://www.marketwatch.com. 23 February 2010.
8 Curtin, Richard. "Improvement in Consumer Confidence Ends." Information available from http://www.reuters.com/universitymichigan. 26 February 2010.
9 U.S. Department of Commerce. "Personal Income and Outlays: January 2010." Information available from http://www.bea.gov. 1 March 2010.

DOMESTIC EQUITY

Brian A. Hooper
Research Analyst

Christina M. Sunderman
Research Analyst

U.S. equities posted gains in February, with the Russell 3000 Index returning 3.4% during the month. Mid capitalization stocks outpaced small and large cap stocks, as the Russell Mid Cap Index posted a 5.0% return, while the Russell 2000 Index and Russell 1000 Index posted slightly lower returns of 4.5% and 3.3%, respectively. There was little discrepancy between the performance of value stocks and growth stocks within all market capitalizations. The Russell 3000 Growth Index returned 3.5% versus 3.3% for the Russell 3000 Value Index. Over the trailing one-year period, mid cap stocks substantially outperformed large and small cap stocks. Performance for the Russell indices in February and the trailing one year is shown in the chart below.



Source: www.russell.com

The global recession severely impacted retailers, as consumer spending fell precipitously in 2009, but showed signs of improvement to start 2010. While U.S. consumer spending is not forecasted to increase substantially in the near term due to high unemployment rates, retailers reported higher sales in February following strong results in January. The increase is largely a result of consumers returning to more normal spending habits versus the frugality exhibited during the recession. Improved inventory management also positively impacted retail sales, as companies maintained higher prices rather than cutting prices to reduce inventory levels.[1] Many retailers began to stock up for spring and summer sales after improved sales early in 2010. Additionally, companies were able to expand their inventories without significantly increasing costs as a result of cheaper materials.[2] Retailers still face the risk of poor consumer demand, however, which could have a significant negative impact on earnings should inventories increase without corresponding sales.

"Retail sales were higher despite looming unemployment and weak consumer confidence, which led to the strong performance of the consumer discretionary sector."

Within the S&P 500 Index, consumer discretionary stocks had the largest positive impact on performance during the month. Retail sales were higher despite looming unemployment and weak consumer confidence, which led to the strong performance of the consumer discretionary sector. The industrials sector also benefited from positive data in manufacturing activity, as measured by The Institute for Supply Management, which reached a five-year high. Technology stocks, namely semiconductor companies, benefited from higher sales amid a cyclical rebound. Additionally, higher commodity prices led to positive returns in the materials sector. Conversely, the health care sector was essentially flat in February. The sector was negatively impacted by poor fourth quarter earnings and guidance from some of the largest health care companies, including Pfizer. Continued weakness in the refining industry had a negative impact on the energy sector within the S&P 500 Index, with Exxon Mobil, Chevron, and Conoco Phillips detracting from performance.[3]

1 Holmes, Elizabeth and Rachel Dodes. "Retail Crocuses in the Snow." *The Wall Street Journal Online*. 5 March 2010.
2 Jannarone, John. "Retailers Get Bullish on Stocks." *The Wall Street Journal Online*. 9 March 2010.
3 "World Markets Review." *Capital Guardian Trust Company*. (February 2010).

INTERNATIONAL EQUITY

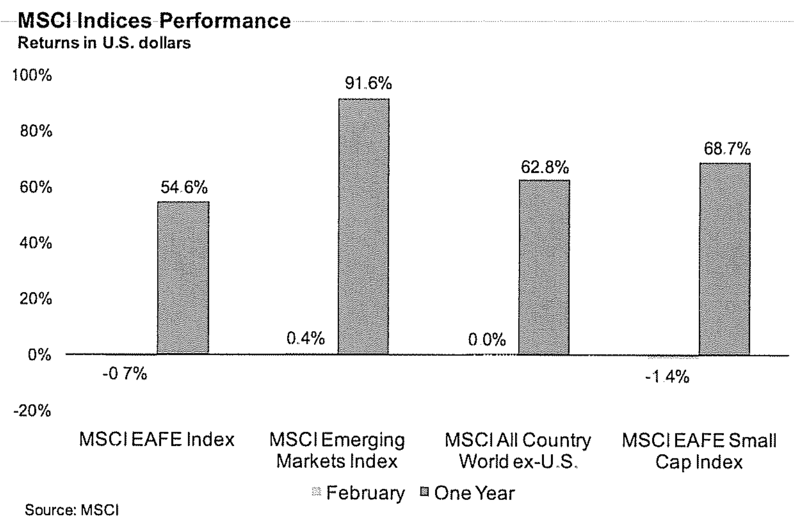
(All returns in U.S. dollars unless otherwise indicated)

Gregory D. Houser, CFA
Vice President

Brian A. Hooper
Research Analyst

"Greece's austerity measures led the Greek citizens to protest and strike."

International equity market returns were relatively flat in February, after posting large monthly moves throughout most of the past year. International developed markets declined 0.7% for the month, as measured in U.S. dollars by the MSCI EAFE Index. The sterling and the euro weakened against the U.S. dollar and detracted from returns for U.S. investors, with the index providing positive returns of 0.5% in local currencies. Emerging market equities posted a slight gain of 0.4% when measured in U.S. dollars. Emerging market currencies generally strengthened against the U.S. dollar, aiding returns for U.S. investors, as local currency returns were -0.2%. International small cap stocks were the weakest segment of international markets, falling 1.4%. The MSCI All Country World ex-U.S. Index, which includes both developed and emerging markets, was flat for the month. Performance of the MSCI Indices is shown in the following chart.[1]



Central banks around the globe held monetary policy steady, with the exception of the United States' change to the discount rate. The Bank of England, European Central Bank, and Bank of Japan did not change target interest rates, and the Bank of Australia paused from recent rate increases to assess the impact on the economy. The U.S. dollar fell approximately 2.0% against the yen and several emerging market currencies, but strengthened 2.0% against the euro and 5.0% against the pound sterling.[2]

Developed Markets

European equity returns were negative in February with declines of 3.6% in the euro zone and 1.5% in the U.K. Concerns surrounding the sovereign debt of Greece created a volatile environment in the region. Markets improved after a plan was announced to support Greece and the European Union worked to contain the debt crises to avoid a contagion spreading to the other "PIIGS" countries of Portugal, Ireland, Italy, and Spain. Germany, France, and other euro zone countries planned to back the debt of Greece while Greece contributed to finding a resolution with efforts to reduce government spending. Greece's austerity measures led citizens to protest and strike, with some demonstrations marred by violence.[3] Stocks in the other "PIIGS" countries followed Greek equity declines, falling approximately 6% in Portugal, Italy, and Spain, while Ireland was down approximately 4%. The U.K. was one of the stronger equity markets, but weakness in the pound sterling offset the positive returns for U.S. investors. The solid returns were driven primarily by industrials and financials, which reported improved earnings. The euro zone economy remained delicate, as economic growth improved only 0.1% from the last quarter. Turmoil in the region weighed on the relatively healthier economies of France and Germany, whose equities were down 2.3% and 2.2%, respectively.[4]

Japanese equity returns were positive (+1.1%) for U.S. investors, attributable primarily to yen strength. Toyota dominated headlines in the auto industry with recalls impacting millions of vehicles and raising questions around the quality and safety of the historically highly regarded company, sending shares down approximately 3% in February and 11% for 2010. While profitability improved at other Japanese automakers, the issues surrounding Toyota impacted these stocks as well. Energy stocks (+7.1%) and utility stocks (+4.8%) provided some of the strongest returns in Japan amid continued growth in Japanese GDP. In Hong Kong, equities climbed 3.9%, as the real estate market showed no signs of cooling. Singapore equities were up almost 1%, with the government's upward revision to their economic growth forecast amid a better than expected GDP measure for the fourth quarter. Australian equities rose 2.6%, led by the consumer staples sector (+8.4%) and health care sector (+7.4%). Materials stocks BHP Billiton and Rio Tinto announced strong profits, with the materials sector returning 3.7%.[5]

Emerging Markets

Emerging market equities were essentially flat, posting a return of 0.4% in February, although country returns were heavily dispersed. In Latin America, Brazil gained 4.5%, bolstered by strong performance in consumer discretionary and materials stocks. Energy giant, Petrobras stood to benefit from proposed legislation that would grant the company increased access to the nation's oil reserves for additional government stock ownership. Chile was devastated by a large earthquake that destroyed infrastructure and disrupted production, leaving equity markets down 1% for the month. Financials in Mexico posted double-digit returns, leading Mexican equities up 4.3%.[6]

In Asia, Chinese stocks rose 2.2%, as fears surrounding tightening from elevated lending levels declined despite an additional 50 basis point increase in the bank reserve requirement to 16.5%. Korean stocks fell slightly, down 0.8%, led by declines in technology stocks that suffered from potential weak consumer demand. Indian stocks rose 1.4% with the government's budget plan to curb the deficit. In Europe, Turkish equities declined over 9% amid the detainment of approximately 50 military officers in an apparent coup that highlighted the disparity between Islamic influences and the military's role as guardian of the country's secular traditions.[7] Russian equities fell 6.3%, as Gazprom declined with the completion of plans to build a $10 billion pipeline that will circumvent the Ukraine.[8]

1 All performance data from http://www.mscibarra.com. MSCI Barra. Accessed on 9 February 2010.
2 Bloomberg L.P.
3 Sebastian Moffett and Costas Paris, "Nationwide Strike Paralyzes Greece." Wall Street Journal, 25 February 2010.
4-6 "World Markets Review." Capital Guardian Trust Company. (February 2010).
7 Marc Champion, "Turkey Charges 11 More in Coup Plot." Wall Street Journal, 26 February 2010.
8 "World Markets Review." Capital Guardian Trust Company. (February 2010).

FIXED INCOME

Broad Market Overview

Keith M. Berlin
Vice President

The Barclays Capital Aggregate Bond Index (BCAG) gained 0.4% in February. Within the BCAG, only the smaller sectors, such as investment grade commercial mortgage-backed securities, which comprise 3% of the benchmark, outperformed, with gains of 1.9% on the month. Asset-backed securities comprise less than 1% of the benchmark, but gained 0.5%. These two securitized sectors benefited from strong demand due primarily to the success of both the Term Asset Backed Securities Lending Facility (TALF) and the Treasury's Public Private Investment Program (PPIP), which targeted these sectors with inexpensive government sponsored leverage. Within the larger areas of the BCAG, Treasuries and investment grade corporate bonds performed in-line with the index, while agency mortgage-backed securities underperformed, gaining 0.2%.

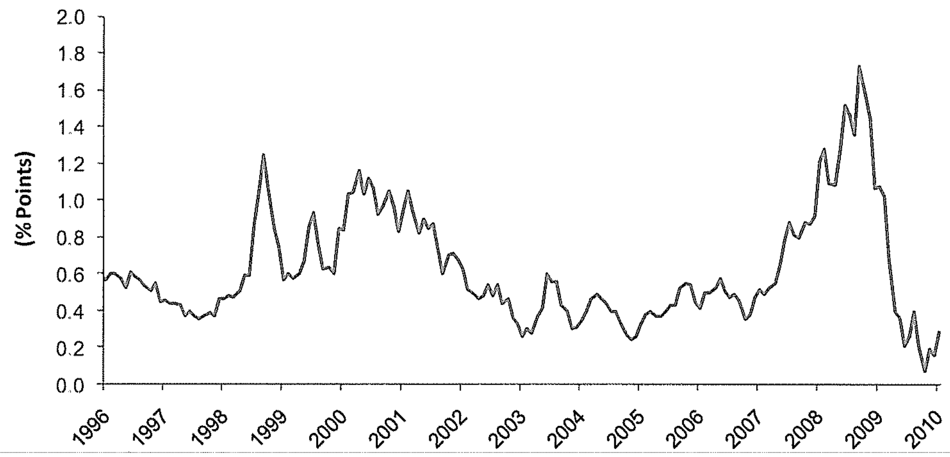
Securitized Sectors Outperform (ex-Mortgages)

"A shift in favor of higher quality securities led to better performance for investment grade corporate bonds."

Securitized sectors benefited from increased demand, as government-sponsored programs have supported these markets, placing a technical bid underneath the bonds. As a result, some traditional fixed income and hedge fund managers increased their exposures to these areas of the markets, further extending prices and decreasing yield spreads. The TALF program, which provides low-cost loans to securitized bond buyers, helped spur $178 billion of issuance in 2009 and $4.8 billion in the first two months of 2010,[1] but is set to expire in March 2010 for securitized bonds (ex-commercial mortgage backed securities, which ends in June 2010). This program has been effective supporting these markets as private investors left these areas in 2008. While spreads could widen for new issuance in these markets after the conclusion of the program, private investors have returned to the market with a better sense of the risk level inherent in these securities, suggesting minimal impact on new issuance.

Agency mortgage-backed securities underperformed the broad market, up 0.2% as option-adjusted spreads widened by 12 basis points (0.12%) in February. Option-adjusted spreads of 0.28% remain well below the historical average of 0.63%, and have been below this average for most of 2009 and 2010, as the Federal Reserve agency mortgage purchasing program nears its completion. While earlier indications suggested the end of this buying program could have a material impact on option-adjusted spreads, the removal of purchasing limits on "wards of the State" Freddie Mac and Fannie Mae, will allow buying to continue, which should keep spreads near current levels for some time.

Barclays US MBS Option-Adjusted Spreads (Over Treasuries)



Source: Bloomberg

Corporate Bond Sector Returns Mixed

Within investment grade corporate bonds, returns were mixed, with industrials gaining 0.5%, utilities returning 0.4% and financials increasing 0.2%. The performance differential between intermediate and longer-dated bonds was relatively muted among industrials and utilities companies. Within financials, however, the performance was divergent, with intermediate financials gaining 0.3% and longer-dated financials declining 0.4%. The move in longer-dated financials was significantly different that comparable Treasuries, suggesting investors have become more concerned about the longer-term prospects for financial institutions. Unimplemented but anticipated financial reforms have the potential to lead to lower earnings for large financial institutions, possibly giving investors incentive to look for other areas to place their long-term investments.

High Yield Bonds and Bank Loans Underperform

High yield bonds and bank loans gained 0.2% and 0.3%, respectively in February. A shift in favor of higher quality securities led to better performance for investment grade corporate bonds and higher rated high yield bonds and loans relative to lower quality issuers. Within the high yield bond market, BB-rated bonds gained 0.5% while B-rated and CCC-rated bonds declined by 0.2% and 0.4%, respectively. An increase in supply with a modest down-tick in demand was a net negative driver of returns for high yield in February. High yield bond funds saw outflows for the first time since March 2009, although new issuance remained robust.

Treasuries Rally on "Flight-to-Quality" Concerns

U.S. Treasuries rallied in February due primarily to "flight-to-quality" concerns with Greece's debt challenges, which casted a negative light on other areas of the European Union as well. The result was stronger Treasury prices and a strengthening U.S. dollar, suggesting that the traditional "flight-to-quality" trade remains in tact despite lingering challenges of the credit crises and ensuing rhetoric about the U.S. dollar as reserve currency. TIPS lost ground in February, declining 1.2%, as inflation concerns waned.

Major Fixed Income Indices

	Feb-10	YTD
Barclays Capital Aggregate Bond	0.4%	1.9%
Barclays Capital U.S. TIPS	-1.2%	0.4%
Barclays Capital Government	0.4%	1.9%
Barclays Capital Municipal Bond	1.0%	1.5%
Barclays Capital Asset-Backed	0.5%	2.2%
Barclays Capital Mortgage-Backed	0.2%	1.6%
Barclays Capital Credit	0.4%	2.0%
Barclays Capital High Yield	0.2%	1.4%
Barclays Capital Investment Grade CMBS	1.9%	6.4%
Barclays Capital High Yield CMBS	4.0%	9.4%
Merrill Lynch BB-B Index	0.3%	1.5%
CSFB Leveraged Loan Index	0.3%	2.1%
JP Morgan Emerging Market Bond Plus Index	1.6%	1.5%
JP Morgan Emerging Market Local Plus Index	0.0%	-0.3%
JP Morgan Global Bond Non-US (US$)	0.5%	1.0%
JP Morgan Global Bond Non-US (Unhedged)	0.2%	0.3%
90-Day US LIBOR	0.0%	0.0%

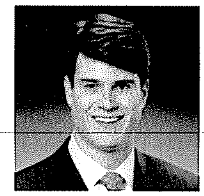
Source: Bloomberg

1 All data in the index from Bloomberg, L P

REAL ESTATE SECURITIES

Domestic

Christian Busken
Vice President



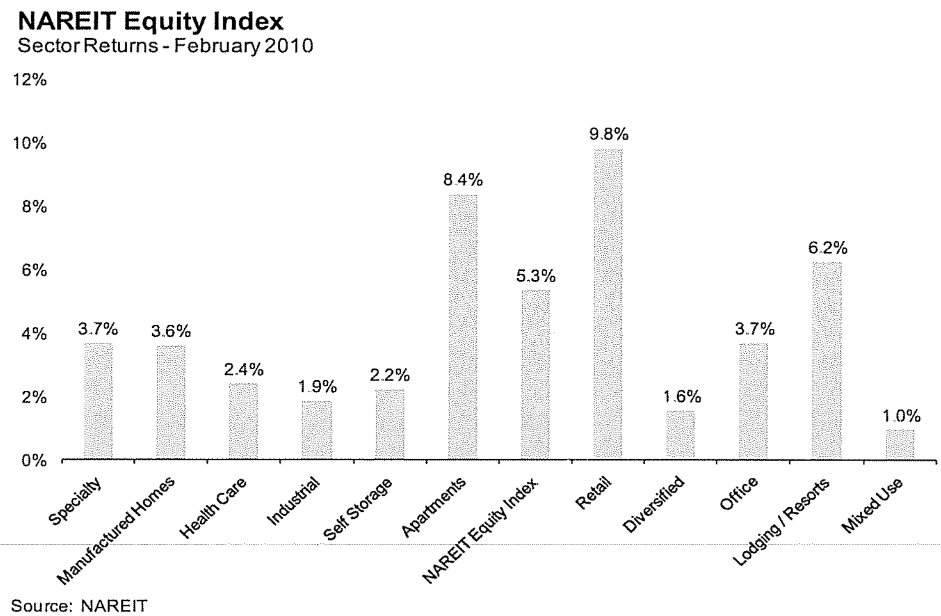
Jay R. Johnston
Research Analyst

Real estate investment trusts (REITs), as measured by the NAREIT Equity Index, outperformed the broad equity market in February, gaining 5.3% versus an increase of 3.1% for the S&P 500 Index.[1] All major property sectors posted positive returns for the month, as REITs benefitted from stabilized balance sheets after raising new equity capital in 2009, which gave them the ability to deleverage considerably. Conversely, private real estate markets continue to work through issues related to massive debt restructurings and further write-downs of asset values.

Contributing to REITs' outperformance was the reinstatement of cash dividends. Companies that recapitalized began trying to put new cash to work, as illustrated by the current bidding war for General Growth Properties (GGP). In February, the bankrupt owner of more than 200 malls in the U.S. received an unsolicited bid by Simon Properties (a $10 billion offer for 100% ownership of GGP, with $7 billion retiring all existing unsecured debt and $3 billion paid to GGP shareholders) and a competing bid from Brookfield Asset Management.[2] Brookfield offered $2.6 billion to breakup the company into two separate entities, the 180 good performing assets to remain GGP and 19 distressed assets to be held under a newly formed opportunistically focused company.[3] Ongoing bankruptcy court proceedings will influence the outcome of General Growth. Elsewhere, progress in the CMBS market remained slow, as dealers had difficulty sourcing and closing suitable mortgages.[4] A glimmer of hope for a CMBS revival was seen in February, however, as Deutsche Bank announced plans to package its $41.5 million loan made to Keystone Property Group.[5] The deal would mark the first multi-borrower CMBS offering in nearly two years and is expected to close sometime in the second quarter.[6] A renewed CMBS market would be an important factor for property owners and developers needing to refinance mounting debt in the coming years.

"Contributing to REITs' outperformance was the reinstatement of cash dividends as companies recapitalized."

The top performing property sector within the NAREIT Equity Index for February was the retail sector (+9.8%), which benefitted from a renewed sense that American consumer sentiment is improving. Supporting retail was the recent decline in the U.S. personal savings rate, showing signs that consumers were becoming open to spend more and save less, contrary to previous post-recession assumptions.[7] The apartment (+8.4%) and lodging/ resorts (+6.2%) sectors also outperformed. Apartments were driven in part by capital flow, with investment volume up 182% from a year ago even as office and retail property volumes fell 33% and 43%, respectively, on the same basis.[8] In contrast, the industrial sector (+1.9%) underperformed on a relative basis for the month, as did the mixed use (+1.0%), diversified (+1.6%), and self storage sectors (+2.2%). As of the end of February, the average U.S. REIT dividend yield was 4.2%, compared to the yield on 10-year Treasuries of approximately 3.6%.

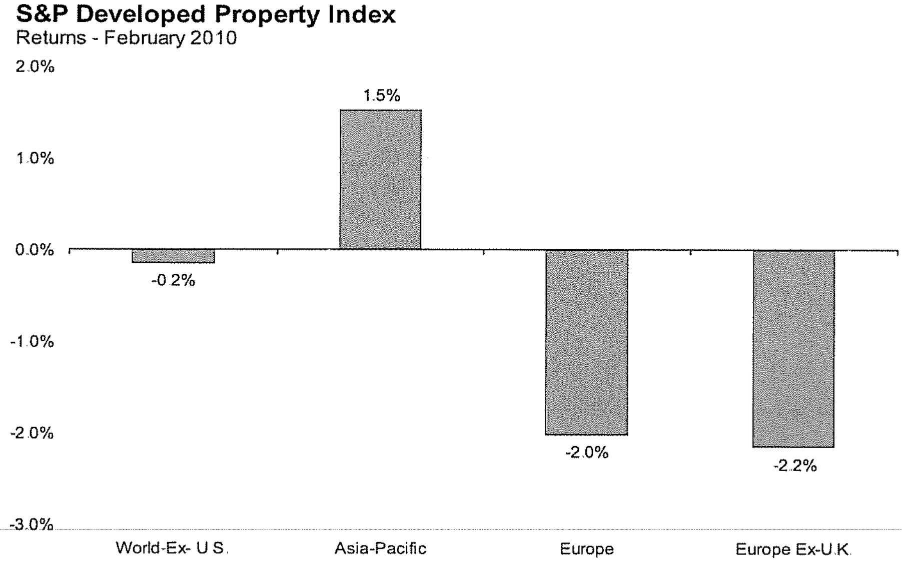


International

(All returns stated on a U.S.-dollar basis)

International real estate securities underperformed domestic REITs in February, with the S&P Developed Property Ex-U.S. Index declining 0.2%, versus a gain of 5.3% for U.S. REITs.[9] Within the international markets there was notable segmentation in real estate performance in Europe versus Asia. Property stocks in Europe ex-U.K. (-2.2%) were shaken again this month by Greece's mounting fiscal troubles and massive budget deficit, as spillover caused many investors to re-examine the euro-zone as a whole. Sovereign yields rose in several other countries (most notably Portugal, Italy and Spain), where similar fiscal issues have raised concerns.[10] Germany and France, however, as well as other solvent EU countries, committed to help guarantee Greece's loans with final details to be worked out in the coming weeks.[11] The euro fell 2% versus the U.S. dollar in February, which further detracted from returns for U.S. investors. The stability of the euro remains contingent on stricter ECB enforcement of sovereign debt levels and less acceptance of countries maneuvering around the fiscal constraints mandated by the euro-zone's monetary authority.

The Asia-Pacific region (+1.5%) outperformed the international index, led by strength in investments in China and Hong Kong. Around the region, easy credit and abundant liquidity fueled concerns that prices may be rising to unsustainable levels. In China (+3.3%), net new loans increased through the first quarter (growing by over $200 million from the end of 2009) and caused the People's Bank of China to continue to temper lending.[12] Speculators in Shanghai maintained demand for properties, causing prices to rise by over 150% since 2003 and allowing some luxury-apartments to command $2,300 per square foot, a $400 premium to Manhattan's average in late 2009.[13] The Hong Kong property sector (+3.2%) remained buoyant amid strong results in a government-sponsored land auction, raising concerns that an asset bubble might be brewing there as well.



Source: S&P

1 All performance data from www.nareit.com and www.sp-indexdata.com.
2 Kary, Tiffany. "General Growth Biased Towards Brookfield Proposal, Creditors Say". Bloomberg. March 3, 2010.
3 Hudson, Kris & McCracken, Jeffrey. "Westfield Weighs Bid for General Growth". The Wall Street Journal. February 25, 2010.
4 CB Richard Ellis Investors. "U.S. Capital Watch – March 2009".
5 Wei, Lingling. "In Pennsylvania, Hope for CMBS". The Wall Street Journal. February 10, 2010.
6 Ibid.
7 Bureau of Economic Analysis. "Personal Income and Outlays".
8 CB Richard Ellis Investors. "U.S. Capital Watch – March 2009".
9 All performance data from www.nareit.com and www.sp-indexdata.com.
10 Capital Guardian. "World Markets Review – February 2010".
11 Ibid.
12 CB Richard Ellis Investors. "Asian Econowatch – March 2010".
13 Barboza, David. "Market Defies Fear of Real Estate Bubble in China". The New York Times. March 4, 2010.

HEDGE FUNDS

The broad hedge fund indices of the HFRI Fund Weighted and HFRI Fund of Funds Composite gained 0.5% and 0.1%, respectively, during February. This performance was mixed when compared to the traditional, long-only indices of the S&P 500, 3.1%, and Barclays Capital Bond Aggregate, 0.4%. The hedge fund index returns were slightly negative for the first two months of the year with the Fund Weighted Composite down 0.2% and the Fund of Funds Composite down 0.3%. This performance compared favorably to equity indices, with the S&P 500 down 0.6%, but lagged the Barclays Capital Bond Aggregate, up 1.9%.

The health of the hedge fund industry continues to improve. In a recent report, hedge fund adviser Hennessee Group estimated hedge funds realized new asset growth of 37% in 2009. That 37% represented an estimated $448 billion of new capital inflows, the largest amount in the history of hedge funds. Charles Gradante, co-founder of Hennessee Group, was quoted, "New assets are coming from the traditional long-only side; in part due to the horrendous losses in 2008 coupled with an improved comfort level with hedge funds for those institutions with 10 or more years experience in hedge funds." A separate hedge fund database provider, Eurekahedge, also provided encouraging news for the industry as they projected a 14% increase in hedge fund assets in 2010.

Another proxy of hedge fund industry health has been the increase in hedge fund launches. After peeking in 2007 with 10,096 hedge funds, the industry declined to 9,050 at the end of 2009. Since then, hedge fund openings increased substantively as Alex Ehrlich, Head of Prime Brokerage at UBS, commented, "The number of launches we are seeing are five times stronger than what we saw last year. We are seeing very, very strong hedge fund formation."

There were also a few recent regulatory items worth noting. One such issue was an amended short sale rule by the Securities Exchange Commission. Rule 201 implements a so-called "circuit breaker" when securities are experiencing an intra-day 10% price decline. If a stock falls below the 10% trigger, an "alternative uptick rule" would be in effect allowing short sales only when the stock trades at a price above the current national best bid. This would prevent short-sellers from conceivably driving the price down by piling on sell orders. A second regulatory matter was the draft submission of the "Volker rule" by President Obama's administration to Congress. The Volker Rule, named after former Federal Reserve Paul Volker, would include several prohibitive measures against investment banks including a ban of proprietary trading, prohibition of sponsoring or ability to invest in hedge funds or private equity funds, limitation of prime brokerage relationships, an increase of capital requirements, and potential caps of market share.

J. Alan Lenahan, CFA, CAIA
Managing Principal /
Director of Hedged Strategies

Gregory M. Dowling, CFA, CAIA
Managing Principal /
Director of Hedged Strategies

David L. Mason
Research Analyst

"The ratio of long positions to short positions decreased materially from 53% at the end of the year to 44% at the end of January."

Directional

The broad HFRI Equity Hedge (Total) Index returned 0.6% in February and -0.6% year-to-date. Managers who were quick to increase their risk appetite during the "V" shaped recovery the first few quarters of 2009 continued to display tempered optimism. Most anticipate company specific fundamentals will again drive valuations with healthy companies being rewarded and lower quality names penalized. This "reversion to dispersion" should create an ideal environment for fundamental stock pickers.

A recent Credit Suisse prime brokerage update highlighted the uncertainty in the equity markets. Credit Suisse found that in the portfolios of their hedged equity managers, the ratio of long positions to short positions decreased materially from 53% at the end of the year to 44% at the end of January. This derisking was even more pronounced in Emerging Market regions, as the ratio dropped from 157% to 69%. Leverage for Credit Suisse hedged equity managers remained steady since the second quarter of 2009, increasing marginally from 2.0x to 2.1x.

While hedge funds remained wary of equities during February, tactical trading/global macro managers were constructive in asset classes such as commodities, currencies, and rates. The HFRI Macro (Total) Index gained 0.8% during the month. Credit default swaps (CDS) on the sovereign debt of Greece and the euro were popular trades during the month. Legendary hedge fund manager George Soros commented the euro, "may not survive." He went on to say the "makeshift assistance may be enough for Greece," but was skeptical of the long-term strength of the euro as it faced future headwinds in other PIIGS countries (Portugal, Italy, Ireland, and Spain). When compared to the U.S. dollar, the euro lost nearly 2% during the month.

London based hedge fund, GLG Partners, has taken a contrarian view of Greece and the euro to many of their peers. Portfolio manager, Karim Abdel-Motaal, said, "We don't believe it (Greece) is as large a problem as the market is making it out to be. We are certainly not short in the face of what we believe is very likely a German-led bailout. Nor are we particularly enamored with spreads for us to be long, expecting some big rally. So we're sort of indifferent on Greece." Abdel-Motaal also commented, "I'm bullish on the euro. Within the constellation of currencies that are ... performing an 'ugliness' contest -- the dollar, sterling, the euro, and the Japanese yen -- by which I mean central banks printing money, the euro is in a better place than most."

Managers also benefitted from short positioning and CDS trades on the British pound as concerns over budget deficits and upcoming Parliamentary elections were a detriment to the pound. The pound fell nearly 5% when compared to the U.S. dollar in February.

Commodities were also a driver to tactical trading performance during the month. The price of oil increased 9.3% to $80 per barrel, driving the energy-heavy Goldman Sachs Commodity Index up 6.4%. In general, tactical traders performed better than longer-term, thematic traders. Sugar was a headwind for several systematic-trend following programs, as many were long the commodity. The price of sugar fell approximately 18% during the month and was down 10% in the last week alone. This precipitous drop was preceded by a steep 40% swell in the price in under two months. In addition, the price of cocoa continued to fall under the pressure of heavy investor outflows. Despite some of these obstacles, managers within the HFRI Macro: Systematic Diversified Index gained 1.0% in February.

Short biased equity managers realized strong gains in January as markets fell, but suffered difficult performance as equity markets sharply bounced off their lows. These managers were some of the poorest performers in the industry during the month, second only to Russian/Eastern European focused equity managers. The Equity Hedge Short-Bias Index fell 3.2% in February and is now down 0.7% for 2010.

Hedge funds with developed equity exposure generally outperformed their Emerging Markets counterparts. The HFRI Emerging Markets (Total) Index return was down 0.7% in February, bringing year-to-date performance to -1.8%.

Performance within Emerging Market regions was mixed, however, as Latin America realized gains, 1.0%, while Asia ex -Japan gave up 0.2%, and Russia/Eastern Europe, the weakest index tracked by HFRI, fell 4.0%.

Statistical arbitrage strategies (technical managers who rely on complex computer algorithms to determine high frequency trading) benefitted from an uptick in volatility in February. While volatility, as measured by the VIX, appeared to be subdued (down 20.8% month-over-month), the VIX opened the month at 24.6, spiked to 26.5 during the height of the Greek debt crises the first week of February, and eventually closed the month at 19.5. The HFRI Equity Hedge Quantitative Directional Index was the best performing strategy during the month, up 2.0%.

Absolute Return

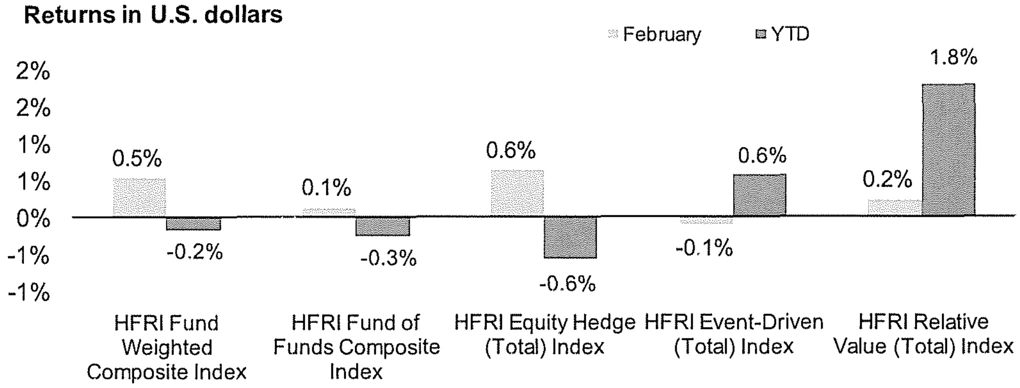
The HFRI Relative Value (Total) built upon a strong January gaining an additional 0.2% in February. The index is now up 1.8% for 2010. Multi-strategy was particularly strong, returning 0.5% during the month. Multi-strategy managers have been the strongest performers year-to-date returning 2.8%. After effectively riding the credit beta wave of 2009, multi-strategy managers began monetizing gains and trimmed credit exposure for areas such as distressed/restructuring and catalyst driven event.

The broad HFRI Event Driven (Total) Index (-0.1%) fell slightly in February. Within the broad index, the sub-component of the HFRI Event Driven Distressed/Restructuring Index returned 0.4% during February. Distressed/ Restructuring managers were some of the strongest performers year-to-date and were up 2.2%. One of the explanations of positive performance within the group has been the sustained rally of mall operator General Growth Properties. Simon Properties, a rival of General Growth Properties, made an offer to acquire the firm in early February for $10 billion. General Growth rejected that bid calling it "not sufficient" anticipating a possible bidding war from other real estate firms including Vornado Realty Trust and Brookfield Properties. Hedge funds with substantial positions in General Growth include Bill Ackmans' Pershing Square and Whitney Tilson's T2 Partners. Other post-reorganization equities that have been key contributors to hedge fund performance include the small/middle market lender, CIT Group, and advertising company, SuperMedia.

In our last Research Review, we discussed the default of the sprawling Manhattan apartment complex of Stuyvesant Town and Peter Cooper Villages. BlackRock Realty and Tishman Speyer Properties purchased the complex four years ago at $5.4 billion, but were unable to restructure a wall of maturing debt. They agreed to turn the properties over to lenders. The iconic Manhattan properties would no doubt pique the interest of distressed oriented hedge funds and in the latter part of February, David Tepper's Appaloosa Management acquired a significant portion, $750 million, of the complex's mortgages. Appaloosa sought to take control of the properties, filing a motion to intervene in U.S. District Court against the real estate finance and investment management company, CW Capital Management. Appaloosa claims CW Capital Management, the servicer of a sizable portion of the CMBS debt on Stuyvesant Town, is acting "irrationally and imprudently" and could cost debt holders hundreds of millions of dollars if they foreclose on the properties, as opposed to filing bankruptcy.

The HFRI Event Driven Merger Arbitrage Index gained 0.5% in February, despite relatively muted levels of M&A activity. Larger deal announcements in February included First Energy, the country's fifth largest public power company, purchasing Allegheny Energy for $4.7 billion and the unsolicited bid of Airgas by Air Products & Chemicals, the gas, materials, and equipment provider. The $60.00 per share hostile bid was a 38% premium to the close prior to the announcement and was 18% above the Airgas' 52 week high. Airgas' Board of Directors formally rejected the bid on February 22.

HFRI Indices Performance
Returns in U.S. dollars



Source: HedgeFund Research

DISCLOSURES

Indices:

Russell Investments rank U.S. common stocks from largest to smallest market capitalization at each annual reconstitution period (May 31). The primary Russell Indices are defined as follows: 1) the top 3,000 stocks become the Russell 3000 Index, 2) the largest 1,000 stocks become the Russell 1000 Index, 3) the smallest 800 stocks in the Russell 1000 Index become the Russell Midcap index, 4) the next 2,000 stocks become the Russell 2000 Index, 5) the smallest 1,000 in the Russell 2000 Index plus the next smallest 1,000 comprise the Russell Microcap Index.

S&P 500 Index consists of 500 stocks chosen for market size, liquidity, and industry group representation, among other factors by the S&P Index Committee, which is a team of analysts and economists at Standard and Poor's. The S&P 500 is a market-value weighted index, which means each stock's weight in the index is proportionate to its market value and is designed to be a leading indicator of U.S. equities, and meant to reflect the risk/return characteristics of the large-cap universe.

Morgan Stanley Capital International – MSCI - A series of indices constructed by Morgan Stanley to help institutional investors benchmark their returns. There are a wide range of indices created by Morgan Stanley covering a multitude of developed and emerging economies and economic sectors.

Barclays Capital Fixed Income Indices – an index family comprised of the Barclays Capital Aggregate Index, Government/ Corporate Bond Index, Mortgage-Backed Securities Index, and Asset-Backed Securities Index, Municipal Index, High-Yield Index, and others designed to represent the broad fixed income markets and sectors within constraints of maturity and minimum outstanding par value.

The FTSE NAREIT Composite Index (NAREIT Index) includes only those companies that meet minimum size, liquidity and free float criteria as set forth by FTSE and is meant as a broad representation of publicly traded REIT securities in the U.S. Relevant real estate activities are defined as the ownership, disposure, and development of income-producing real estate.

The HFRI Monthly Indices (HFRI) are equally weighted performance indexes, compiled by Hedge Fund Research Inc., and are used by numerous hedge fund managers as a benchmark for their own hedge funds. The HFRI are broken down into 37 different categories by strategy, including the HFRI Fund Weighted Composite, which accounts for over 2,000 funds listed on the internal HFR Database. The HFRI Fund of Funds Composite Index is an equal weighted, net of fee, index composed of approximately 800 fund of funds which report to HFR. See www.hedgefundresearch.com for more information on index construction.

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Index performance results do not represent any managed portfolio returns. An investor cannot invest directly in a presented index, as an investment vehicle replicating an index would be required. An index does not charge management fees or brokerage expenses, and no such fees or expenses were deducted from the performance shown.

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Past performance is not indicative of future results.

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
8/30/2004 5:43	4.9	Alberta Electric System Operator (AESO)	WECC-NWPP	Y	N	N	UO	0	N/A	Maintenance error	On August 30, 2004 at about 0538 PDT, system protection removed from service two high voltage transmission lines while a higher voltage transmission line was being removed from service for routine maintenance. With these three transmission lines out of service, the control area was separated from the Western Interconnection. There was no loss of customer load, system frequency swing, or any other facility affected. At 0558, the two high voltage transmission lines were returned to service, synchronizing the control area to the Interconnection. At about 0705, a false metering signal from one of the terminals of the high voltage transmission line that was out of service for maintenance. This resulted in a false ACE signal. As the control area attempted to recover its ACE, system protection once again removed the same two high voltage transmission lines due to overloading, resulting in another separation from the Interconnection. At about 1034, the two high voltage transmission lines were returned to service, synchronizing the control area to the Interconnection again. There was not customer load or any other facilities affected by these two incidents.	N	N	No FIRM demand interruption reported	Y	
8/30/2004 18:58	52.0	Dominion - Virginia Power, North Carolina Power	SERC-VACAR	Y	Y	N	INT	99,816	150	Weather - Tropical Storm Gaston	On August 30, 2004 at about 1858 EDT, Tropical Storm Gaston caused widespread distribution outages within Virginia and North Carolina. Several high voltage transmission lines were removed from service by system protection and manual control of the utility's system operators. The storm had minimal effect in northern and western Virginia. As a result of this storm about 80,000 electric customers lost service.	Y	Y		Y	5,229
9/4/2004 8:00	352.0	Florida Power and Light Company	FRCC	Y	N	N	INT	1,807,881	6,000	Weather - Hurricane Frances	On September 4, 2004 at about 0800 EDT, winds from Hurricane Frances started causing widespread outages with damage to the distribution system, and some high voltage transmission line outages. As of 2000 on 9/5/2004, about 1,807,881 electric customers were without power in Florida. Hurricane Francis moved slowly through the area and continued to cause damage for more than 24 hours.	Y	Y		N	1,415,040
9/6/2004 13:00	71.0	Southern Company	SERC-Southern	Y	N	N	INT	556,383	3,000	Weather - Hurricane Frances	On September 6, 2004 at about 1300 EDT, Hurricane Frances caused widespread outages in parts of Georgia. About556,383 electric customers were effected by this storm.	Y	Y		N	142,710
9/15/2004 19:00	48.0	Southern Company	SERC-Southern	Y	N	N	INT	1,536,433	1,364	Severe Weather - Hurricane Ivan	On September 15, 2004 at about 1900 EDT, Hurricane Ivan caused widespread distribution outages due to damage sustained by high winds. About 1,536,433 electric customers were affected by this storm.	Y	Y		N	43,866
9/16/2004 2:00	108.7	Alabama Electric Cooperative, Inc.	SERC	Y	N	N	INT	75,000	263	Weather - Hurricane Ivan	On September 16, 2004 at 0200 EDT, Hurricane Ivan caused widespread distribution outages. There were approximately 75,000 electric service customers affected by this storm. As of September 20, 2004 at 14:50 EDT, all electric customer service had been restored.	Y	Y		N	19,148
9/18/2004 5:30	98.5	Progress Energy - Carolinas (Carolina Power and Light)	SERC	Y	N	N	INT	112,000	400	Severe weather - Hurricane Ivan	On 9/18/2004 at about 0430 EDT, Hurricane Ivan caused widespread distrubtion outages. About 112,000 electric custmers were affected by this storm. All electric customers had been restored by 12:00 EDT on 9/22/2004.	Y	Y		N	26,398
9/25/2004 19:00	404.0	Florida Power and Light	FRCC	Y	N	N	INT	1,700,000	6,000	Severe Weather - Hurricane Jeanne	On September 25, 2004 at about 1900 EDT, Hurricane Jeanne came ashore approximately at Stuart, Florida, as a category 3 hurricane with winds of 115 mph. The storm has caused both transmission and distribution outages in an area around West Palm Beach, Florida. Damage assessments will not begin until approximately 1300 EDT, as the area is still experiencing hurricane force winds. As a result of this event, about 1,700,000 electric customers are without power.	Y	Y		N	1,624,080
9/27/2004 8:00	6.0	Southern Company	SERC-Southern	Y	N	N	INT	85,455	854	Severe weather - Hurricane Jeanne	On September 27, 2004 at about 0800 EDT, widespread electric customer outages occurred as a result of Hurricanne Jeanne. About 85,455 electric customers were affected.	Y	Y		N	3,433
10/17/2004 13:40	3.0	PacifiCorp, Western Area Power Administration - CM	WECC-RMPA	Y	N	N	UO	0	N/A	System Protection malfunction	On October 17, 2004 at 13:40 MDT, a high voltage transmission line was open-ended because system protection received a transfer trip signal from the opposite end of the line. An area special protection scheme was armed, but did not send a generator trip signal to an area power plant. Because of the open-ended transmission line, another high voltage transmission line and a step down transformer became overloaded. In addition, another high voltage step down transformer was removed from service by system protection. Also, removed from service by system protection was another high voltage transmission line. Area generation and interchange schedule were curtailed to control the flows on the overloaded elements. There was no generation lost, or electric customer interruptions due to this incident.	N	N	No FIRM demand interruption reported	Y	
10/25/2004 11:00	9.0	Entergy Transmission Services	SERC-Entergy	Y	N	N	PA	0	N/A	Public Appeal	On October 25, 2004 at 1100 CDT, a utility issued a public appeals to its electric service customers to conserve electric consumption due to the loss of a transformer breaker failure that resulted in the loss of two generating units. In addition to the loss of generation, unseasonably warm temperatures caused the utility to issue this public appeal. The public appeals were broadcast from 1100 to 1700 CDT on October 25, 2004 and again from 0500 to 1000 CDT on October 26, 2004. All affected generating units had been restored by 0916 CDT, on October 26, 2004.	N	N	Public Appeal	Y	

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Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
10/30/2004 10:00	61.0	Consumers Energy	ECAR	Y	Y	Y	INT	117,842	60	Weather - high winds	On October 30, 2004 at 1000 EDT, a windstorm with winds gusting to about 55 MPH caused widespread distribution outages. In addition, three high voltage transmission lines were removed from service due to these winds. About 117,842 electric customers were affected by this storm. By 11/1/2004 at 2400 EST, all electric customer electric service had been restored.	Y	Y		Y	2,452
11/5/2004 2:41	1.5	Entergy Energy Services	SERC-Entergy	Y	N	N	UO	0	N/A	EMS Computer failure	On November 5, 2004 at 0241 CT, a utility experienced an EMS computer system failure with its primary and backup EMS computers. No abnormal events occurred as a result of this failure. By 0414 CST, the EMS computers had been restored.	N	N	No FIRM demand interruption reported	Y	
11/7/2004 20:17	1.0	Manitoba Hydro Electric Board	MAPP-Canada	Y	Y	Y	UO	0	N/A	SPS misoperation	On November 7, 2004 at 2017 CST, an HVDC flow reduction scheme operated due to a false signal received. The control area's EMS indicated that a high voltage ac transmission line tripped, which initiated the SPS. Upon investigation, no circuit breaker operations were found. There was no generation or electric customer service interrupted due to this incident.	N	N	No FIRM demand interruption reported	Y	
11/12/2004	27.5	Cinergy	ECAR	Y	Y	Y	UO	0	N/A	EMS computer failure	On November 12, 2004 (time unknown), the main EMS computer for a control center failed because of the failed UPS. The control center functions were transferred to its backup facility. At 0330 on 11/13/04, the EMS was restarted and control functions transferred after replacing the failed UPS. There was no generation or electric customer service lost as a result of this incident.	N	N	No FIRM demand interruption reported	Y	
11/14/2004 2:00	0.4	Novia Scotia Power, Inc. and New Brunswick Power	NPCC-Maritimes	Y	Y	N	INT	132,000	600	Weather - severe snow storm	On November 14, 2004 at about 0455 EST, a strong northeaster winter blizzard hit Nova Scotia. The storm produced 18 inches of wet snow, with winds up to 55 mph. Several high voltage transmission and distribution lines were damaged by the storm. Nova Scotia became islanded from New Brunswick at about 0455 EST. The storm continued throughout the day. Additional high voltage transmission lines were damaged. About 100,000 electric customers were interrupted because of this storm.	Y	Y		Y	181
11/20/2004 7:05	0.3	Entery Energy Services	SPP	Y	Y	N	UO	0	N/A	EMS Computer Failure	On November 20, 2004 at 0705 CST, a utility lost both its primary and secondary EMS computer systems during planned building maintenance. During the time that the EMS system was disabled, a special protection scheme was non-operational. As a result of the building outage, the utility's control center automatically switched to a backup power source and the EMS computers were restored by 0725 CST.	N	N	No FIRM demand interruption reported	Y	
11/23/2004 11:20	0.3	British Columbia Transmission Company	WECC-NWPP	N	N	N	UO	88,775	370	Equipment failure	On November 23, 2004 at 1120 PST, during a routine fault test, a disconnect blade broke and fell across two phases of energized equipment at a high voltage substation. The resulting fault was slow in clearing, causing several high voltage transmission lines and a single small generating unit to be removed from service. In addition, 370 MW of firm customer load was interrupted. About 88,775 electric service customers were interrupted as a result of this incident. By 1126, all transmission lines had been restored. By 1140, electric service to all customers was restored. At 1148, the single generating unit had been restored.	Y	Y		Y	83
11/24/2004 10:00	6.0	Southern Company	SERC-Southern	Y	N	N	INT	83,450	100	Severe weather - thunder storms	Severe thunder storms caused widespread electric customer outages. About 83,450 electric service customers were without power as a result of this storm system.	Y	Y		Y	402
11/30/2004 14:33	3.0	Arizona Public Service	WECC-AZNMSNV	Y	N	N	UO	0	N/A	Maintenance Error	On November 30, 2004 at 14:33 MST, multiple generating units were removed from service by normal system protection. The cause of the trouble is not known at this time. There was no electric customer load lost as a result of this incident.	N	N	No FIRM demand interruption reported	Y	
1/18/2005 13:25	0.1	Manitoba Hydro	MAPP-Canada	Y	Y	Y	UO	0	N/A	SPS misoperation	On January 18, 2005 at 1325 and again at 1333 CDT, a special protection scheme caused the reduction of 331 MW of area generation after receiving a false signal due to faulty microwave equipment. The faulty module has been replaced. This incident did not cause any loss of customer load.	N	N	No FIRM demand interruption reported	Y	
1/29/2005 10:00	62.0	Southern Company	SERC-Southern	Y	N	N	INT	150,000	100	Weather - severe winter storm	On January 29, 2005 at 1000, a severe winter storm caused widespread distribution outages in parts of Alabama and Georgia. Approximately 150,000 electric service customers were affected by this storm.	Y	Y		Y	4,153
3/8/2005 11:00	19.0	Progress Energy - Carolinas (Carolina Power and Light Company)	SERC	Y	N	N	INT	51,600	180	Severe weather - wind storm	On March 8, 2005 at 1100 EST, a severe wind storm caused widespread outages in Eastern and Central North Carolina. Approximately 51,600 electric customers were interrupted. All customer load was restored by 0600 EST on March 9, 2005.	Y	Y		Y	2,291
3/8/2005 15:55	1.5	PacifiCorp	WECC-NWPP	Y	N	N	UO	0	N/A	Unknown	On March 8, 2005 at 15:55 PST, system protection removed a high voltage transmission line from service. The cause of the fault is unknown. Because of the loss of this transmission line, a special protection scheme was initiated that resulted in 1055 MW of generation being dropped at various hydroelectric generating stations, and a dynamic braking resistor was inserted to prevent excessive power flows on other facilities. There was no interruption to any electric customer load. By 1723, all facilities had been restored to service.	N	N	No FIRM demand interruption reported	Y	
3/17/2005 20:02	1.0	ISO New England	NPCC-ISO-NE	Y	Y	N	INT	0	N/A	Equipment failure	On March 17, 2005 at 2002 EST, system protection removed from service a high voltage transmission line due to a failed splice. A second high voltage transmission line was already out of service for planned maintenance. A contingency analysis indicated possible overloads might occur on lower voltage transmission lines. The utility re-dispatched area generation to prevent any overloads. There was no interruption to any electric service customers because of this incident.	N	N	No FIRM demand interruption reported	Y	

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4/2/2005 12:11	4.1	PacifiCorp, Western Area Power Administration, RM	WECC-RMPA	Y	N	N	INT	0	N/A	Equipment Overload	On April 2, 2005 at 1211 MST, system protection removed from service a high voltage transmission line due to an overloading condition. Prior to the outage, another higher voltage transmission line was removed from service for scheduled maintenance. Area generation had been reduced to allow for the scheduled maintain outage. In addition, the high voltage step-down transformers at one substation became overloaded. A second high voltage transmission line was manually removed from service to relieve the loading on these transformers. Area voltages remained within normal limits. There were no other overloaded facilities because of this incident. There was no loss of electric customer load or generation. The transmission system was normal by 1616 MST.	N	N	No FIRM demand interruption reported	Y	
4/20/2005 14:08	1.0	Sacramento Municipal Utility District	WECC-CAMX	Y	N	N	INT	48,000	200	Human error	On April 20, 2005 at 1408 PDT, during routine switching to restore two high voltage step-down transformers to service, a switchman inadvertently opened the wrong switch, which caused unbalanced flows across the switch and the arc to ground triggered system protection to remove from service two other high voltage step-down transformers. This resulted in the loss of approximately 200 MW of firm customer load. About 48,000 electric customers were interrupted as a result of this incident. By 1506 PDT, all electric service had been restored.	Y	Y		Y	130
4/21/2005 21:29	0.4	Sacramento Municipal Utility District	WECC-CAMX	Y	N	N	INT	48,000	168	Human error	On April 21, 2005 at 2129 PDT, while a crew was removing its personal grounds during routine switching to restore a high voltage switch that had been damaged the previous day, it made contact with an energized potential transformer (PT). This caused the activation of the system protection, which removed from service two high voltage step-down transformers. This resulted in the loss of approximately 168 MW of firm customer load. About 48,000 electric customers were interrupted as a result of this incident. By 2155 PDT, all electric service had been restored.	Y	Y		Y	49
4/22/2005 14:14	0.2	Sacramento Municipal Utility District	WECC-CAMX	Y	N	N	INT	69,979	127	RTU malfunction	On April 22, 2005 at 1414 PDT, a substation remote terminal unit (RTU) malfunctioned. Because of this malfunction, about 127 MW of firm load and approximately 69,979 electric customers were interrupted when multiple high voltage transmission lines and three high voltage step-down transformers were opened ended at the substation involved. By 1425, all firm loads were restored to the electric customers interrupted. By 1434, all transmission facilities were normal. The local RTU was disabled until repairs were completed.	Y	Y		Y	16
4/30/2005 8:00	2.0	Southern Company	SERC-Southern	Y	N	N	INT	51,808	100	Weather - severe thunder storm	On 4/30/2005 at 0800 CDT, a severe thunder storm moved through the area causing the loss of electric service to about 51,800 eclectic customers.	Y	Y		Y	134
5/8/2005 15:00	50.0	CenterPoint Energy Houston Electric	ERCOT	Y	Y	N	INT	243,000	672	Severe weather - thunderstorms	On May 8, 2005 at about 15:00 CDT, a series of strong thunderstorms moved across a utilities service territory causing widespread distribution outages. At the peak of these storms, about 243,000 customers had their electric services interrupted. By about 1700 on May 10, 2005 CDT, all customer electric service had been restored.	Y	Y		Y	22,512
5/19/2005 8:07	0.2	Bonneville Power Administration	WECC-NWPP	Y	N	N	INT	0	N/A	Lightning	On May 19, 2005 at 0807 PDT, system protection momentarily removed from service a high voltage transmission line due to a possible lightning strike. Because of this event, a special protection scheme activated as designed. Remedial actions that occurred included local generation dropping of 1,683 MW of generation, and other remedial actions designed to prevent localized low voltages on the AC transmission system. No interruptible or firm load was shed because of this event. The transmission system was stabilized and normal within nine minutes.	N	N	No FIRM demand interruption reported	Y	
5/19/2005 13:47	0.2	Bonneville Power Administration	WECC-NWPP	Y	N	N	INT	0	N/A	Lightning	On May 19, 2005 at 1347 PDT, system protection momentarily removed from service a high voltage transmission line due to a possible lightning strike. Because of this event, a special protection scheme activated as designed. Remedial actions that occurred included local generation dropping of 966 MW of generation, and other remedial actions designed to prevent localized low voltages on the AC transmission system. No interruptible or firm load was shed because of this event. The transmission system was stabilized and normal within twelve minutes.	N	N	No FIRM demand interruption reported	Y	
5/25/2005 14:17	0.1	Hydro-Quebec - TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	System Protection	On May 25, 2005 at 1417 EDT, system protection, inadvertently, removed from service a high voltage transmission line. This caused the initiation of the special protection scheme to remove from service 1130 MW of generation at a local generating plant because of the loss of the high voltage transmission.	N	N	No FIRM demand interruption reported	Y	
5/27/2005 15:15	1.1	Independent Electric System Operator, Independent Electricity Market Operator	NPCC-Ontario	N	Y	N	INT	N/A	2,300	Human Error	On May 27, 2005 at 1515 EST, system protection removed from service several high voltage transmission lines when operating personnel closed a high voltage circuit breaker during routine switching to restore a high voltage bus after maintenance. Operating personnel failed to recognize that grounds that had been applied to the high voltage bus had not been removed. Because of this incident, approximately 2,300 MW of firm customer load was shed. In addition, approximately 750 MW of local generation was removed from service due to low station service voltage that occurred as the firm load was rapidly being restored. The transmission system and generating units were restored by 16:20 EST. All electric customer load was restored within about 60 minutes from the initial incident	Y	Y		Y	1,669
5/29/2005 20:00	45.0	CenterPoint Energy Houston Electric	ERCOT	Y	Y	N	INT	123,000	328	Weather - severe thunderstorms	On May 29, 2005 at about 20:00 CDT, a strong thunderstorm caused widespread distribution outages throughout a utilities service area. At the peak of the storm, about 123,000 electric customers were interrupted. By May 31, 2005 at 17:00 CDT, all electric customers had been restored.	Y	Y		Y	9,889

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5/30/2005 13:54	N/A	Comision Federal de Electricidad	WECC-CAMX	Y	Y	N	INT	N/A	53	Unknown	On May 30, 2005 at 1354 PDT, system protection removed from service three high voltage transmission lines due to a fault at a transmission substation. The cause of the fault is unknown. Because of this incident, a total of 333 MW of local generations was also removed from service. In addition, 52.9 MW of firm electric customer load was interrupted. By 1417 PDT, all firm electric customer load was restored.	N	Y		Y	
5/31/2005 16:09	0.2	Bonneville Power Administration	WECC-NWPP	Y	N	N	INT	0	N/A	Weather - Lightning	On May 31, 2005 at 1609 PDT, system protection removed from service a high voltage transmission line due to a lightning strike. This incident initiated a special protection scheme requiring 1,887 MW of area generation to be dropped. Upon line inspection, a parted insulator string was found that was damaged by the lightning strike. Repairs to the transmission line were completed on June 1, 2005. The area generation was restored by 1621 PDT. There was no interruption to firm electric customer load because of this incident. The special protection scheme responded properly.	N	N	No FIRM demand interruption reported	Y	
6/1/2005 13:36	0.1	Bonneville Power Administration	WECC-NWPP	Y	N	N	INT	0	N/A	Damage Insulators	On June 1, 2005 at 1336 PDT, system protection removed from service a high voltage transmission line due to damaged insulators. The cause of the insulator damage is unknown. Because of this incident, a special protection scheme initiated various remedial actions. Remedial actions include the removal of shunt reactors, generation dropping of 426 MW, and opening a Direct Current tie line. There was no loss of firm electric customer load because of this incident. Local generation was restored by 1340 PDT. The high voltage transmission line was returned to service on June 2, 2005 after making repairs.	N	N	No FIRM demand interruption reported	Y	
6/2/2005 13:10	5.3	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	INT	415,000	1,500	Forrest fires	At 1310 EDT on June 2, 2005, a sequence of events caused by adverse climatic conditions, thunder storms and severe forest fires, caused a special protection scheme to operator after system protection removed from service three high voltage parallel transmission lines into a generation complex. Because of these events, 2,100 MW of generation was rejected by a special protection scheme. About 1,500 MW of firm customer load was shed during this event that caused the interruption to the electric service of about 415,000 customers.	Y	Y		Y	5,310
6/6/2005 12:07	0.0	Hydro-Quebe - TransEnergie	NPCC-HQ	N	Y	N	UO	0	N/A	Weather - Severe Lightning	On June 6, 2005 at 1207 EST, system protection removed from service a high voltage transmission line because of a lightning strike. Because of the incident, a special protection scheme initiated to reject 750 MW of local generation. There was no firm load loss because of this incident. System conditions were normal by 1208.	N	N	No FIRM demand interruption reported	Y	
6/7/2005 18:01	1.0	New Brunswick System Operator, Inc.	NPCC-Maritimes	Y	Y	N	INT	2	14	Weather - lightning storm	On June 7, 2005 at 1801 AST, system protection removed from service a high voltage transmission line because of a lightning strike that damaged an insulator and caused one phase to part. Because of this incident, a control circuit activated to remove a high voltage dc tie-line from service. The dc circuit was exporting 255 MW to an adjacent region. Local generation was reduced due to the loss of the dc circuit. In addifion, about 14 MW of interruptible load at two industrial customers was shed because of the resulting voltage dip in the area. All interruptible loads was restored by 1900 on June 7, 2005. Repairs to the high voltage transmission line were completed by 1334 on June 8, 2005.	Y	Y		Y	9
6/13/2005 10:04	2.8	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Equipment Failure	On June 13, 2005 at 1004 EDT, system protection removed from service a high voltage transformer and two HVDC converters following a breaker failure operation. Because of this incident there was an interruption to 630 MW of export from the utility into a neighboring system. There was no loss of genertion or firm customer electric service because of this incident. By 1240 EDT, the two HVFC converted had been restored. There was no explanation as to why the breaker failure occurred.	N	N	No FIRM demand interruption reported	Y	
6/14/2005 14:15	0.5	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Telecommunications failure	On June 14, 2005 at 1415 EST, a special protection scheme initiated, causing 710 MW of local generation to be shed due to a telecommunications problem. There was no loss of customer electric load because of this incident.	N	N	No FIRM demand interruption reported	Y	
6/15/2005 18:55	4.6	Entery Energy Services - Transmission	SPP	Y	Y	N	INT	150,000	1,100	Weather - high winds	On June 15, 2005 at 1855 CDT, a severe storm with high winds caused multiple transmission line outages. In addition, three local generating units were removed from service by system protection due to the loss of the transmission lines. This incident cause electric service interruptions to about 1,100 MW of firm load serving about 150,000 customers. All electric customer load was restored by 2330 CDT.	Y	Y		Y	3,378
6/19/2005 7:10	6.8	Manitoba Hydro	MAPP-Canada	Y	Y	Y	INT	15,000	N/A	Weather - tornado	Strong winds caused two 230 kV lines to trip which correctly initiated a special protection system running back the HVDC by 346 MW. Problems occurred with the reset of one biplole reset when the runback was complete causing it to continue ramping down until it was stopped at a 275 MW power order. This resulted in an additional 950 MW HVDC capacity loss. The inadvertent additional runback caused three lines at the rectifier end of the HVDC to overload and subsequently trip. The tripping of these lines and coincident loss of a valve group caused another 700 MW reduction in the HVDC generation.	N	N	No FIRM demand interruption reported	Y	
6/21/2005 10:04	0.1	Bonneville Power Administration	WECC-NWPP	Y	N	N	UO	0	N/A	Weather - lightning	On June 21, 2005 at 1004 PDT, system protection removed from service a high voltage transmission line due to a lightning strike. This incident initiated a special protection scheme that removed from service 980 MW of area generation. At 1005, the high voltage transmission line was returned to service and at 1013, area generation was restored. There was no loss of firm load or electric service customers because of this incident. The special protection scheme operated properly.	N	N	No FIRM demand interruption reported	Y	

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6/21/2005 20:02	0.3	Seattle City Light	WECC-NWPP	Y	N	N	UO	0	N/A	Weather - lightning	On June 21, 2005 at 2002 PDT, system protection removed from service two high voltage transmission lines due to a lightning strike. Both transmission lines auto reclosed properly. This caused a special protection scheme to remove from service 766 MW of area generation. At 2022 PDT, all area generation was restored. The special protection scheme operated properly. There was no firm demand or electric service customers lost because of this incident.	N	N	No FIRM demand interruption reported	Y	
6/21/2005 22:45	N/A	Alberta Electric System Operator	WECC-NWPP	Y	N	N	INT	N/A	200	Weather - severe winds and lightning	On June 21, 2005 at 22:45 PDT, system protection removed from service several high voltage transmission lines as a severe wind and lightning storm passed through a utility's service area. Heavy rain, large hail and tornado velocity winds were associated with this storm. Preliminary reports indicate that about 200 transmission structures sustained damage, along with some damage at local substations. Because of this incident, about 200 MW of electric customer load was lost. Much of this load was industrial. There was no indication of the total number of electric customers involved, or when restoration would be completed. The local utility was still assessing damages at the time of this report.	N	N	Restoration Time Unknown	Y	
6/23/2005 1:18	0.1	Hydro-Quebec TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Unknown	On June 23, 2005 at 0118 EDT, a 670 MW generating unit was removed from service by unit automatics during switching operations. Cause of the incident is unknown. At 0123, the unit was restored to service.	N	N	No FIRM demand interruption reported	Y	
6/24/2005 20:37	2.5	Commonwealth Edison Company	MAIN	Y	Y	N	INT	51,500	350	Equipment failure	On June 24, 2005 at 2037 CDT, system protection removed from service two high voltage underground transmission cables due to a fault. Because of the cable fault, the cable casing ruptured causing the insulating oil to ignite. Because of the fire, several other high voltage transmission lines were deenergized for safety while firefighters attempted to extinguish the fire. These underground transmission cables run in a common tunnel. Because of the transmission line outages, a single 340 MW local generating unit was removed from service. This incident caused the loss of about 51,500 electric service customers. All customer load was restored by 2306 CDT.	Y	Y		Y	582
6/28/2005 12:45	N/A	Public Service Company of Colorado	WECC-RMPA	Y	N	N	UO	0	N/A	Fuel supply problems	On June 28, 2005 at 1245 MDT, a utility company reported an interruption to one of its coal rail transportation systems at a local coal-fired generating station. The utility redispatched area gas-fired generation to meet its demands adequately. There was no public appeal to conserve power issued because of this incident. There was no loss of firm load to any electric customer due to this incident.	N	N	No FIRM demand interruption reported	Y	
7/1/2005 13:13	3.4	ERCOT ISO, TXU ED	ERCOT	Y	Y	N	INT	N/A	100	Unknown	On July 1, 2005 at 1313 CDT, system protection removed from service a high voltage step-down autotransformer when the overload relay actuated. Because the autotransformer configuration does not include high-side circuit breakers two associated high voltage transmission lines were also removed from service. Because of this incident the low side voltage dropped to about 0.9 p.u. An associated low-side bus was then removed from service and the low-side voltage dropped to 0.816 p.u before firm load shedding began. About 100 MW of firm customer load was shed. At 1530 CDT, system protection removed another high voltage circuit breaker by overcurrent. The loss of this circuit breaker caused a special protection scheme to shed about 174 MW of interruptible loads. By 1634 CDT, the utility had all firm and interruptible loads restored. The total number of electric customers involved in this incident is unknown.	Y	Y		Y	224
7/9/2005 10:21	1.1	PacifiCorp East	WECC-RMPA	Y	N	N	Int	18,600	150	Equipment failure	On July 9, 2005 at 1021 MDT, system protection removed from service a high voltage transmission bus and several high voltage transmission lines due to a breaker failure operation on a circuit breaker to a station capacitor bank. Because of this incident about 150 MW of firm electric customer load, and about 69 MW of interruptible customer load was interrupted. About 18,600 electric customers were interrupted. In addition, 20 MW of customer owned local generation was removed from service. By 1128 MDT, all firm electric customer load, and the interruptible loads were restored.	Y	Y		Y	112
7/10/2005 8:00	N/A	Southern Company	SERC-Southern	Y	N	N	INT	66,830	45	Weather - Hurricane Denis	On July 10, 2005 starting at about 0800, Hurricane Dennis moved through the Florida, Mississippi, Alabama and Georgia areas causing wide-spread electric customer outages. The peak total of electric customers that were without power occurred at 0800 on July 11, 2005 when about 570,899 customers were without power.	N	Y		Y	
7/10/2005 12:53	28.0	Alabama Electric Coop, Inc.	SERC	Y	N	N	INT	50,000	51	Weather - Hurricane Dennis	On July 10, 2005 at about 12:53 EDT, Hurricane Dennis caused widespread distribution outages throughout the Southwestern parts of Alabama, and the western panhandle area of Florida. Approximately 50,000 electric customers were interrupted as a result of the high winds and damage to the distribution system.	Y	Y		Y	961
7/11/2005 15:33	0.1	HydroQuebec - TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Equipment failure	On July 11, 2005 at 1533 EDT, system protection removed from service a high voltage transmission line due to the failure of a series capacitor. Because of the loss of this transmission line, a special protection scheme initiated generation rejection of 750 MW at a local area power plant. System protection and the SPS operations were considered normal. There were no electric customer interruptions due to this incident. The system was returned to normal by 1537.	N	N	No FIRM demand interruption reported	Y	

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7/17/2005 13:16	0.7	HydroQuebec - TransEnergie	NPCC-Quebec	N	Y	N	UO	361,166	1,173	Human error	On July 17, 2005 at 13:16 EDT, system protection removed from service two high voltage transmission lines during routine testing of system protection relays. At the time of the incident a third high voltage transmission line was already out of service for voltage control. Because of the loss of three transmission lines about 2,600 MW of area generation was dropped at various generating stations. This caused a drop in the system frequency to a low of 58.41 Hz, which then initiated underfrequency relays. About 1,173 MW of firm electric customer loads were interrupted due to the underfrequency relaying. About 361,166 electric customers were interrupted because of this incident. At 13:44 EDT, two of the high voltage transmission lines were returned to service. By 14:00 EDT, all firm electric customer loads were restored. The cause of this incident will be investigated further.	Y	Y		Y	576
7/19/2005 12:50	0.3	Bonneville Power Administration	WECC-NWPP	Y	N	N	UO	0	N/A	Human Error	On July 19, 2005 at 12:50 PDT, a special protection scheme initiated a trip signal that caused about 1,440 MW of area generation to be removed from service. In addition, the special protection scheme also inserted a braking resistor as part of a remedial action scheme that would occur with the loss of a high voltage transmission line. The keying of the line loss signal was inadvertent. There was no transmission line outage. There was no loss of electric customer load, or any other problems noted. By 1306, all area generation had returned to service.	N	N	No FIRM demand interruption reported	Y	
7/19/2005 14:06	1.7	HydroQuebec - TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Weather - lightning	On July 19, 2005 at 14:06 EDT, system protection removed from service two high voltage transmission lines due to a lightning strike. Because of this incident about 930 MW of area generation was dropped. Although the system frequency dropped to 59.33 Hz, no underfrequency load shedding occurred. There was no loss of electric service to any firm customer loads. By 1551 EDT, all generating units, and the transmission lines had been restored to service.	N	N	No FIRM demand interruption reported	Y	
7/28/2005 20:30	92.5	Duke Energy Company	SERC	Y	N	N	INT	52,200	300	Weather - severe thunderstorm	On July 28, 2005 starting at about 2030 EDT, a series of strong thunderstorms passed through a utilities service area causing widespread distribution outages. About 52,200 electric customers were interrupted. Repairs were completed and all electric customer loads were restored by 1700 on 8/1/2005.	Y	Y		Y	18,593
8/1/2005 23:07	0.6	HydroQuebec - TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Weather - lightning	On August 1, 2005 at 2307 EDT, system protection removed from service two high voltage transmission lines due to a lightning strike. Because of this incident, about 887 MW of area generation was removed from service. There was no interruption to any firm or non-firm electric customer load.	N	N	No FIRM demand interruption reported	Y	
8/9/2005 17:36	0.2	HydroQuebec- TransEnergie	NPCC-Quebec	N	Y	N	UO	0	N/A	Weather - severe lightning storm	On August 9, 2005 at 1736 EDT, system protection removed from service a high voltage transmission line due to a lightning strike. Because of this line outage, a special protection scheme initiated the removal of 930 MW of area generation. There was no interruption to any electric customer loads because of this incident. All system protection and the special protection scheme functioned as designed. By 1749, the transmission line and all area generation had been returned to service.	N	N	No FIRM demand interruption reported	Y	
8/25/2005 15:47	1.3	California ISO, Southern California Edison, Los Angeles Dept. of Water and Power, PacifiCorp West, Bonneville Power Administration	WECC-CAMX	Y	Y	N	INT	N/A	1,700	Equipment failure	On August 25, 2005 at 1547 PDT, system protection removed from service one pole of a high voltage DC transmission line due to the loss of one converter. This caused an automatic reduction in the dc line's power order. In addition, a special protection scheme initiated various remedial actions including: insertion of series capacitor banks along a high voltage AC transmission path. At 1550, a transmission emergency was declared on one of the high voltage AC transmission paths in an adjacent system. At 1551, area utilities were ordered to shed non-firm interruptible loads to reduce the flow across the overloaded transmission path. At 1551, the high voltage dc transmission line began ramping to zero to terminate the ground return operation of the dc line. This caused increased power flows in the AC transmission paths, and a decline in system frequency. At 1553, the special protection scheme initiated additional remedial actions that resulted in dropping about 2249 MW of area generation. Because of declining system frequency, about 224 MW of firm electric customer load was shed. An additional 1,000 MW of load shedding was requested to stop the frequency decline. About 1,700 MW of both non-firm and firm electric customer load was dropped. At about 1608, system frequency was stable and load restoration began. By 1705, all non-firm, and firm electric customer loads were restored. The cause of the converter failure is not known. A further investigation will take place.	Y	Y		Y	1,481
8/26/2005 2:10	12.8	City of Homestead	FRCC	Y	N	N	INT	17,500	38	Weather - Hurricane Katrina	On August 26, 2005 at 0210 EDT, system protection removed from service two high voltage transmission lines from service due to high winds associated with Hurricane Katrina on the eastern shore of Florida. This resulted in the loss of about 75% of the electric customers within the service area. By 1500, the transmission lines had been restored and the majority of the electric customers' services restored. Clean up was hampered by strong winds and flooding in the area.	Y	Y		N	327
8/29/2005 1:10	1,001.3	Louisiana Generating LLC	SPP	Y	Y	N	INT	143,000	300	Weather - Hurricane Katrina	On August 29, 2005 at about 0710 CDT, Hurricane Katrina started causing widespread outages throughout the Gulf shore area.	Y	Y		N	201,268
8/29/2005 6:45	675.2	Cleco Power, LLC	SERC	Y	N	N	INT	50,800	380	Weather - Hurricane Katrina	On August 29, 2005 at about 0645, Hurricane Katrina caused widespread damage and electric customer outages. Estimated that 50,800 electric customers were without electricity.	Y	Y		N	171,919
8/29/2005 7:10	14.8	Southern Company	SERC-Southern	Y	N	N	INT	897,257	8,972	Weather - Hurricane Katrina	On August 29, 2005 at about 0710 CDT, Hurricane Katrina started causing widespread outages throughout the Gulf shore area.	Y	Y		N	89,165

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9/10/2005 21:46	0.5	Alberta Electric System Operator	WECC-NWPP	N	N	N	UO	8,000	8	Weather - high winds and snow	On September 10, 2005 at 2146 PDT, system protection removed from service a high voltage transmission line due to high winds and wet snow. Before this incident occurred, two lower voltage transmission lines had been removed from service due to the same storm. With the loss of the transmission line at 2146, the system separated from the Western Interconnection. AT 2218, the high voltage transmission line was returned to service. There was 8 MW of firm electric customer load lost as a result of the loss of the two lower voltage transmission lines. This affected about 8,000 electric customers.	Y	Y		Y	3
9/12/2005 12:32	3.4	Burbank Water & Power, Los Angeles Department of Water & Power	WECC-CAMX	Y	N	N	INT	50,686	172	Human Error	On September 12, 2005 at 12:32 PDT, system protection removed from service two high voltage transmission buses at a central substation because of a problem with the secondary relay wiring on a break back up scheme. This either open-ended or removed from service several high voltage transmission lines. Subsequently, this caused automatic underfrequency load shedding. In addition, this caused the need for additional manual load shedding. About 2,200 MW of electric customer load was shed among several area utilities. At the same time, about 691 MW of local area generation was removed from service. The reason for the loss of this generation is under investigation. Firm load was shed because the main transmission grid operates in a loop configuration, with only a few ties across the loop. Opening the loop caused large power flows across one portion of the transmission system that caused circuit overloads and low voltage in the area. Additional manual load shedding was needed in a effort to increase area voltages and reduce transmission line overloading. At the time of this incident, maintenance personnel were moving a relay panel and may have incorrectly wired a portion of the system protection, or cut into secondary wiring of the relay circuits.	Y	Y		N	392
9/12/2005 12:32	1.7	City of Glendale, Los Angeles Department of Water & Power	WECC-CAMX	Y	N	N	INT	63,000	130	Human error	On September 12, 2005 at 12:32 PDT, system protection removed from service two high voltage transmission buses at a central substation because of a problem with the secondary relay wiring on a break back up scheme. This either open-ended or removed from service several high voltage transmission lines. Subsequently, this caused automatic underfrequency load shedding. In addition, this caused the need for additional manual load shedding. About 2,200 MW of electric customer load was shed among several area utilities. At the same time, about 691 MW of local area generation was removed from service. The reason for the loss of this generation is under investigation. Firm load was shed because the main transmission grid operates in a loop configuration, with only a few ties across the loop. Opening the loop caused large power flows across one portion of the transmission system that caused circuit overloads and low voltage in the area. Additional manual load shedding was needed in a effort to increase area voltages and reduce transmission line overloading. At the time of this incident, maintenance personnel were moving a relay panel and may have incorrectly wired a portion of the system protection, or cut into secondary wiring of the relay circuits.	Y	Y		N	152
9/12/2005 12:32	1.4	Los Angeles Department of Water and Power, Southern California Edison, and the City of Glendale	WECC-CAMX	Y	N	N	INT	900,000	2,200	Human Error	On September 12, 2005 at 12:32 PDT, system protection removed from service two high voltage transmission buses at a central substation because of a problem with the secondary relay wiring on a break back up scheme. This either open-ended or removed from service several high voltage transmission lines. Subsequently, this caused automatic underfrequency load shedding. In addition, this caused the need for additional manual load shedding. About 2,200 MW of electric customer load was shed among several area utilities. At the same time, about 691 MW of local area generation was removed from service. The reason for the loss of this generation is under investigation. Firm load was shed because the main transmission grid operates in a loop configuration, with only a few ties across the loop. Opening the loop caused large power flows across one portion of the transmission system that caused circuit overloads and low voltage in the area. Additional manual load shedding was needed in a effort to increase area voltages and reduce transmission line overloading. At the time of this incident, maintenance personnel were moving a relay panel and may have incorrectly wired a portion of the system protection, or cut into secondary wiring of the relay circuits.	Y	Y		N	2,064
9/13/2005 18:30	77.5	Wisconsin Energies	MAIN	Y	Y	Y	INT	110,000	600	Weather - severewinds	On September 13, 2005 at about 1800 CDT, a strong cold front with high winds moved through the services territory of a utility that caused widespread electric customer outages. The cold front brought sustained winds of over 60 MPH for the duration of the storm. This caused extensive damage to the distribution system. About 110,000 electric customers lost power during the storm. Repairs will take several days to complete.	Y	Y		Y	31,148
9/14/2005 15:00	24.0	Progress Energy - Carolinas (CP&L)	SERC	Y	N	N	INT	60,000	215	Weather - Hurricane Ophelia	On September 14, 2005 at 15:00 high winds from Hurricane Ophelia caused widespread outages within the distribution system of a utility in eastern North Carolina.	Y	Y		Y	3,457

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
9/20/2005 15:51	0.1	British Columbia Transmission Corporation	WECC-NWPP	Y	N	N	UO	0	N/A	Weather - lightning	On September 20, 2005 at 1551 PDT, system protection momentarily removed from service a high voltage transmission line due to a lightning strike. The transmission line successfully auto-reclosed. At the time of this incident, another high voltage transmission line was out of service for routine maintenance. Because of the momentary loss of the transmission line, a special protection scheme initiated shedding 950 MW of area generation. There was no loss of firm electric customer load because of this incident.	N	N	No FIRM demand interruption reported	Y	
9/21/2005 8:33	0.3	British Columbia Transmission Corportation	WECC-NWPP	Y	N	N	UO	0	N/A	Human error	On September 21, 2005 at 0833 PDT, a high voltage transmission line was inadvertently tripped by operator error during routine switching. At the time of this error, another high voltage transmission line was already out of service for planned maintenance. Because of this incident, a special protection scheme removed from service another high voltage transmission line as part of an islanding scheme. This resulted in a portion of the utility's service area to become islanded from the Interconnection. The island also included an adjacent system. When the islanding occurred, the adjacent system's frequency went to about 60,64 Hz. Because of the high frequency condition about 291 MW of area generation was tripped on over-frequency protection. By 0852, the transmission system had been restored, and the islanded area was reconnected to the Interconnection. There was no firm electric customer load lost because of this incident.	N	N	No FIRM demand interruption reported	Y	
9/22/2005 12:00	N/A	Progress Energy - Florida	FRCC	Y	N	N	PA	0	N/A	Public appeal	On September 22, 2005 at 12:00 EDT, a public appeal for electric customers to temporarily reduce their use of electricity began. This public appeal was in effect until Sunday September 25, 2005 because of Hurricane Rita's probably affect on area fuel supplies in the Gulf of Mexico, Texas, and Florida.	N	N	Public Appeal	N	
9/23/2005 13:06	313.5	Louisiana Generating, LLC	SERC	Y	N	N	INT	125,000	350	Weather - Hurricane Rita	On September 23, 2005 at about 1306 CDT, strong winds associated with Hurricane Rita caused widespread distribution interruptions to about 125,000 electric customers in the western and southwestern area of Louisiana. There was no loss of generation associated with this disturbance. Restoration will take several days to complete.	Y	Y		N	73,516
9/23/2005 17:00	14.5	CenterPoint Energy	ERCOT	Y	Y	N	INT	715,000	1,950	Weather - Hurricane Rita	On September 23, 2005 at 1700 CDT, significant electric customer outages began in Houston area due to strong winds associated with rain bands from the approach of Hurricane Rita toward the upper Texas coast. The winds and storms are causing outages throughout the entire area. Outages to electric customers peaked to 715,000 by 07:00 on September 24, 2005. Crews entered restoration mode at about 07:30 that morning with the first task being reports of lines down across roads as reported by the Houston Police Department and other local officials. Most of the damage was caused by intense wind, lightning and flying debris caused by toppled trees and large branches falling on power lines. The company has more than 4,000 utility personnel from across the country to assist in restoration work. Although crews have been able to bring on large numbers of customers in a short amount of time, some areas have suffered heavier damage, and repairs in these areas may take longer.	Y	Y		N	18,944
9/23/2005 21:00	891.0	Entergy Corporation	SERC-Entergy	Y	N	N	INT	787,774	N/A	Weather - Hurricane Rita	On September 24, 2005 at about 06:00 CDT, strong winds associated with Hurricane Rita caused widespread damage to the transmission and distribution systems in costal areas of Arkansas, Louisiana, Mississippi, and Texas. Because of this storm, electric service to about 787,774 customers was interrupted. Facilities affected included about 271 transmission lines of various voltage levels, and about 275 substations. Two area power plants were also affected by this storm. Restoration will take several days.	N	Y		N	
9/24/2005 6:00	N/A	Cleco Power, LLC	SERC	Y	N	N	INT	80,000	N/A	Weather - Hurricane Rita	On September 24, 2005 at about 0600 CDT, strong winds associated with Hurricane Rita caused widespread damage to the transmission and distribution systems in costal area of Louisiana. Because of this storm, electric service to about 80,000 customers was interrupted.	N	Y		N	
9/24/2005 6:00	203.0	TXU Electric Delivery Company	ERCOT	Y	Y	N	INT	100,000	260	Weather - Hurricane Rita	On September 24, 2005 at 0600 CDT, significant electric customer outages began in Texas coast area due to strong winds associated with rain bands from the approach of Hurricane Rita. The winds and storms are causing outages throughout the entire area. Electric service to about 100,000 customers was interrupted because of the storm. Repairs will take several days.	Y	Y		N	35,363
10/23/2005 23:00	18.0	Florida Power and Light	FRCC	Y	N	N	INT	3,200,000	10,000	Weather - Hurricane Wilma	On October 23, 2005 starting at about 2300 EDT, Hurricane Wilma came ashore on the southwestern area of Florida causing widespread outages within the transmission and distribution systems. The storm moved from west to east across south Florida and impacted Florida for about 12 hours. There were about 3,200,000 electric customers interrupted because of this storm.	Y	Y		N	120,600
10/24/2005 4:11	0.2	City of Homestead	FRCC	Y	N	N	INT	17,500	33	Weather - Hurricane Wilma	On October 24, 2005 EDT, system protection removed from service two high voltage transmission lines from service due to hight winds from Hurricane Wilma. This caused the isolation and shut down of a small single system. The high winds caused extensive damage to the distribution system. A total of 17,000 customers were affected by this incident. By 1545 o n October 25, 2005, one of the transmission lines had been restored, which allowed the utility to restore electric power to about 1,000 customers.	Y	Y		N	6
10/25/2005 18:05	2.4	ISO-New England and Hydro-Quebec TransEnergie	NPCC-ISO-NE	Y	Y	N	UO	0	N/A	Equipment failure	On October 25, 2005 at 1805 EDT, a high voltage dc transmission Intertie was removed from service due to the failure of a reactor at one converter station. The incident did not cause the loss of any customer electric service, or loss of any generation.	N	N	No FIRM demand interruption reported	Y	

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11/2/2005 18:43	1.1	British Columbia Transmission Corporation	WECC-NWPP	N	N	N	INT	2,700	350	Weather - lightning	On November 2, 2005 at 1843 PST, system protection removed from service one high voltage transmission line due to a lightning strike. The high voltage transmission line successfully auto-reclosed after the three-phase fault cleared. Because of the loss of the transmission line, a single high voltage step-down transformer was removed from service that was feeding two low voltage distribution feeder circuits. These circuits were carrying about 20 MW of electric customer load. During the three-phase fault conditions, the voltage dropped significantly on three area high voltage transmission lines. Because of the extreme undervoltage condition, about 350 MW of firm electric customer load was lost. The area's voltage and frequency stabilized within one minute. All firm customer load was restored by 1948 PST. Approximately 2,700 electric customers were interrupted during this incident.	Y	Y		Y	254
11/25/2005 18:01	0.3	Alberta Electric System Operator, British Columbia Transmission Company	WECC-NWPP	N	N	N	INT	N/A	375	Weather - heavy wet snow and freezing rain	At approximately 1801 MST, system protection removed from service a high voltage transmission line. The probable cause was due to heavy wet snow and freezing rain conditions. At the same time, a special protection system removed from service two additional high voltage transmission lines as designed. At approximately 1801, MST, a second utility reported that system protection removed from service another high voltage transmission line. The cause of this transmission line tripped was due to a misoperation of the Zone 1 Distance relay. Because these four transmission lines were opened, one of the two systems became separated from the Western Interconnection. The separated system had been importing energy across the now opened Intertie transmission path. Because of this import, a special protection scheme initiated to drop about 375 MW of interruptible customer load. To counter the loss of system load, a special generating underfrequency fast ramp scheme increased area generation by about 250 MW. All high voltage transmission lines were returned to service by 1819. All interruptible electric customer loads were also restored by 1819.	Y	Y		Y	75
12/15/2005 4:00	157.0	Duke Power	SERC	Y	N	N	INT	600,000	3,000	Weather - ice storm	On December 15, 2005 at about 0400 EST, a major ice storm caused wide-spread electric customer outages in the distribution systems in South and North Carolina.	Y	Y		Y	315,570
12/15/2005 5:05	31.1	Southern Company	SERC-Southern	Y	N	N	INT	52,659	75	Weather 0 ice storm	On December 15, 2005 at about 0505 EST, a major ice storm caused widespread electric customer outages in the distribution system in parts of northern Georgia. About 52,659 electric customers were interrupted. All electric service was restored by1210 EST on December 16, 2005.	Y	Y		Y	1,562
12/15/2005 11:00	4.0	Georgia System Operations Corporation	SERC	Y	N	N	INT	52,000	200	Weather - oce storm	On December 15, 2005 at about 1100 EST, an ice storm hit the northern portion of Georgia causing approximately 52,000 electric customer outages in the distribution system due to ice laden trees falling on distribution lines. In addition, there were several high voltage transmission lines outages during the early morning hours to about 1500 on 12/15/2005. All high transmission lines were restored by 1500 on 12/15/2005. By 1800 on December 16, 2005, electric service had been restored on all customers.	Y	Y		Y	536
12/18/2005 15:15	7.8	Pacific Gas and Electric Company	WECC-CAMX	Y	Y	N	INT	60,000	N/A	Weather - high winds and rain	On December 18, 2005 at 15:15 PST, a winter storm with heavy rains and high winds caused widespread electric distribution outages of about 60,000 electric customers in the San Francisco Bay Area. By about 2300 on December 18, 2005 electric service was restored on all affected electric customers.	N	Y		Y	
12/31/2005 6:00	156.0	Pacific Gas and Electric Company - Northern and Central California	WECC-CAMX	Y	Y	N	UO	1,667,316	800	Weather - High Winds, Rain	Beginning 12/31/ 2005 a series of strong storms brought torrential rain and winds. The saturated ground and high winds/rains caused extensive and rapid flooding and toppled many trees. The initial storm was quickly followed by a second wave of storms that punished the area on 1/1 to 1/2. The storms brought 7-11 inches of rain along the coast, 4-6 in the central valley, and 5-7 in the foothills, as well as up to 10 feet of snow in the mountains. All this triggered widespread flooding, numerous mudslides, the toppling of trees, and snapping of electricity distribution poles. There was extensive damage to the distribution and transmission system. Distribution lost about 530 poles, 459 transformers and 1760 spans of wire. Ninety one transmission lines were affected by the storms. Impacts ranged from momentary outages to broken cross-arms to collapsed towers or broken poles. Additionally, one 500 kV transmission line was forced out of service when floodwaters caused its telemetry and relay protection systems to be unreliable. In all, 157 transmission poles (and/or towers) were damaged along with 35 spans of wire. Twenty generating stations (primarily cogenerator units and hydroelectric generators) were either interrupted or rendered unavailable by the outages on the transmission system. A generating station and associated area were islanded due to transmission failures at 10:34 AM on 1/2. The area load at the time was about 80 MW and was served continuously throughout the islanding event by other generators. Repairs were completed and the island was sychronized to the system at 11:44 AM on 1/2. Early on, the storms affected significant numbers of customers, by 10:00 AM of 12/31 there	Y	Y		N	83,616

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1/14/2006 15:45	49.7	PECO Energy	RFC	Y	Y	N	INT	155,879	N/A	Weather - High Winds	On January 14, 2006 at 1545 EST, high winds, gusting to about 45 MPH, caused widespread electric customer outages within the service area of a utility. An estimated 155,879 electric customers were interrupted during this wind storm. By about 1254 on January 16, 2006 power was restored to all but 2,340 electric customers.	N	Y		Y	
1/18/2006 3:00	44.8	PECO Energy	RFC	Y	Y	N	INT	72,535	N/A	Weather - High Winds	On January 18, 2006 at 0300 EST, high winds, gusting to about 50 MPH, caused widespread electric customer outages within the service area of a utility. An estimated 72,535 electric customers were interrupted during this wind storm. By about 1800 on January 18, 2006 power was restored to all but 23,211 electric customers.	N	Y		Y	
1/21/2006 21:42	N/A	Public Service Company of New Mexico	WECC-AZNMSNV	Y	N	N	INT	2,110	3	Vandalism - Transmission Cable Tampering	On January 21, 2006, at 21:42 MST, system protection removed from service two low voltage transmission lines due to unknown persons throwing a cable up over one phase and the static wire. The low voltage transmission line was automatically restored by protective relaying as the fault cleared. Customer load lost was 3 MW. The line patrol was performed on January 24, 2006. The line patrol identified that someone had thrown a cable up into the transmission phase wires, and the cable was still caught on the static wires. This incident was reported to local law enforcement officers.	N	Y		Y	
1/24/2006 16:00	1.0	Pacific Gas & Electric	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Vandalism - Stray Gunshot	On January 24, 2006 at 16:00 PST, a maintenance crew working at a substation reported hearing the sound of a projectile passing through the area in their vicinity. They also reported hearing the possible impact of a projectile but were unable to locate any damage or physical evidence. They also did not hear the report (sound) of a firearm prior to the incident. No damage was observed of substation equipment, and there was no interruption of station operations. The Sheriff's Office responded to the scene along with the utility's security department. Again, no physical evidence of gunshots was found. There have been no further developments. The cause of the incident is unknown, but we suspect that it was caused by indirect fire from someone target shooting well away from the substation given the failure of the crew to hear gunshots and the lack of damage and physical evidence resulting from the incident.	N	N	No FIRM demand interruption reported	Y	
1/28/2006 6:13	1.0	Pacific Gas & Electric	WECC-CAMX	Y	Y	N	INT	76,000	N/A	Equipment Failure - Transformer Failure	On January 28, 2006 at 6:13 am, system protection removed from service a high voltage stepdown transformer. The cause of this failure is unknown. Because of the incident the electric service to about 76,000 customers was interrupted. All electric service was restored by 7:15 am.	N	N	No FIRM demand interruption reported	Y	
2/4/2006 1:34	46.5	Snohomish County PUD #1, Snohomish County, Washington	WECC-RMPA	Y	N	N	UO	123,827	150	Weather - Wind Storm	On Feb 4, 2006, strong winds blew through the utility speeds of 60 mph. Winds caused trees to fall into four 115-kV and numerous 12-kV distribution lines. The utility used all available resources along with line crews from neighboring utilities to restore the damage. There were 83,434 customers out for over one hour and 40,393 customers for less than one hour. Overall, 123,827 customers were impacted during the storm. The storm was declared over at midnight on Feb. 6.	Y	Y		Y	4,668
2/4/2006 4:30	66.5	Puget Sound Energy, Western Washington Puget Sound Region	WECC-RMPA	Y	N	N	UO	140,000	N/A	Weather - Wind Storm	On Feb. 4, 2004 a regional windstorm caused widespread damage to the utilities transmission and distribution systems. The Emergency Response Plan was initiated in anticipation of this damage. The Emergency Operations Center and all storm bases were opened, a storm management team initiated, and 135 crews were deployed to repair expected damage. As of Feb. 6, over 100 crews are still working on the restoration. As of 4 AM about 5,500 customers were without service. Expectations are that the remaining customers will be restored by today or by the morning of Feb. 7.	N	Y		Y	
2/5/2006 4:19	1.3	Entergy Corporation	SERC-Entergy	Y	N	N	UO	N/A	N/A	Cyber - Hard Drive Equipment Failure	A hard drive failure on the utilities EMS computer at the transmission operations center caused the EMS system to be lost. As a result, SCADA for the area was lost from approximately 4:19 AM until 5:38 AM. The failure caused the utilities SPS to become inoperable and disabled the automatic load-shedding scheme for the area during that same time period.	N	N	No FIRM demand interruption reported	Y	
2/8/2006 3:42	2.8	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Intrusion, Possible Arson	On 2/5/2006, the utilities security personnel observed two male suspests running from the inside fenced area of a substation. County sheriffs and a canine unit searched the substation. A hole was found in the perimeter fence, the dog continued to follow the scent and one (1) suspect was in captured and taken to the hospital for dog bites. Upon final inspection, two holes were found in the fence line and one five gallon can of fuel (gasoline) was found. The suspects vandalism intentions are not known at this time.	N	N	No FIRM demand interruption reported	Y	
2/15/2006 9:00	0.0	Missouri Basin Power Project, Laramie River Station - Basin Electric Power Cooperative (Operator)	MRO	Y	Y	Y	UO	N/A	1,650	Fuel - RR Delivery Problems	The on hand coal inventory at the generating station has dropped below 50% of the normal operating coal inventory. This situation is caused by the lack of timely coal deliveries by the rail carrier.	N	Y		Y	0

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2/18/2006 4:50	N/A	Potomac Electric Power Co; Washington, DC and Vicinity	RFC	Y	Y	N	UO	N/A	N/A	Surveillance - Telephone, War Dialing	On Feb 18, 2006 at about 4:50 AM, System Operations reported the Control Center console phones would ring and when answered there was no one on the line. It was found that the lines were being called sequentially (WAR DIALING). This situation lasted until about 6:40 AM. Extensions not associated with System Operations consoles were also rung in similar manner. Each time, the following scenarios would occur: 1) When the phone was answered, there was a low volume hum on the line. When line was put back on hook, the next sequential line number at the facility would ring; and 2) If a ringing line was not answered, the line would ring four times and then disconnect. The next sequential number at the facility would ring. The utility was not running any penetration testing protocol at the time and no telecom provider was performing maintenance or testing activity during the affected time. The telecom provider has stated that no trace of the originating point is possible. The event impacted voice and other phone numbers at this facility. System operation and the control [SCADA] systems were not impacted by this event since there is no dial up connection to these systems This event was reported for DOE, ES-ISAC/NERC, and the local FBI/JTTF (Joint Terrorism Task Force).	N	N	No FIRM demand interruption reported	Y	
2/18/2006 8:50	1.5	Public Service Company of Colorado (PSC)	WECC-RMPA	Y	N	N	INT	323,000	428	Fuel - Natural Gas Supply and Pressure Limitations	On Feb 18, 2006, record low temperatures (-13F) in the metropolitan area occurred when the Utilities system was deficient by 1,000+ MW of generation due to gas supply and pressure limitations. At 0:44 AM, the utility lost a 186 MW generating station. At 1 AM, a 45 MW generating station tripped. About 4:13 AM, a generating unit that was ramping down for an overhall tripped, losing about 350 MW of capacity. At 5:36 and 6:38 AM two units tripped, an additional 75 MW. In conjunction with the utility, the area's Reliability Coordinator (RC) declared an Energy Emergency Alert 1 (EEA) at 7:16 AM due to increased load and declining reserves. All interruptible loads were curtailed (EEA 1) and all non-firm sales were recalled. The utilities media relations initiate public appeals to conserve energy. Neighboring control areas offered assistance but were unable to provide support because of transmission constraints. At 8:37 AM, a 250 MW of gas turbine was lost and at 8:42 AM an additional 230 MW was lost. At 8:50 AM, due to the last 480 MW of loss, the utility shed approximately 428 MW of firm load to restore reserves and prepare for the next contingency. At 8:51 AM, the utility and the area reliability coordinator declared an EEA 3 requiring rotating shedding of firm load for individual customers every 30 minutes until all systems and normacy were restored at 10:18 AM. A total of 428 MW of firm load was shed, affecting over 323,000 customers, and approximately	N	N	Capacity Issue	Y	421
2/24/2006 9:00	0.0	Public Service Company of New Mexico, Albuquerque	WECC-AZNMSNV	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	Sometime prior to Feb. 24, 2006, the 115 kV switching station had a break-in. The chain securing the gate had been cut and a reel of copper wire was missing. The chain has been replaced and crews have been requested to inspect the fence for any damage. A warning will also be sent to employees to be observant, and report any suspicious behavior, activity or events to Power Operations.	N	N	No FIRM demand interruption reported	Y	
2/27/2006 18:25	46.1	Pacific Gas & Electric Company; Northern and Central California	WECC-CAMX	Y	Y	N	UO	160,000	N/A	Weather - High Winds, Rain	On Feb 27, 2006, a winter storm with high winds and rain swept across the utilities service area causing the interruption of service to approximately 160,000 customers. Sustained 70 MPH winds were reported, with gusts as high as 98 MPH. The winds died down during the night and restoration continued through March 1. All downed lines were restored by 2:30 PM on 3/1/2006.	N	Y		Y	
3/3/2006 13:38	0.9	British Columbia Transmission Company (BCTC), Alberta Electric System Operator (AESO)	WECC-NWPP	Y	N	N	VR	N/A	N/A	Human Error - Voltage Reduction	About 1:38 PM on March 3, 2006, during in-service maintenance on a substation transformer, a protection scheme was inadvertently operated tripping both the transformer and associated protection zones. The action off-loaded the a 500 kV line sending a transfer trip to clear the line. There was no appreciable frequency deviation, however voltage depressed on the southern interior subsystem from 237 kV to 150 kV in one area and from 142 kV to 97kV in another area. A total of 292 MW of load was shed in the parent utility to preserve the bulk transmission system. All transmission lines were returned to service by 2:04 PM, all load by 2:30 PM, and all generation 3:40 PM.	N	N	Voltage reduction	Y	
3/9/2006 14:00	28.0	Entergy Corporation	SERC-Entergy	Y	N	N	UO	73,000	N/A	Weather - Thunderstorms	On March 9, 2006, severe thunderstorms with strong wind gusts, heavy downpours, frequent lightning and isolated tornados moved across the utilities service territory. The system experienced significant outages (10,000-plus customers) by 9:45 AM ad 50,000-plus customers about 12:45 PM. The storms peak was at 1:30 PM with over 72,800 customers out of service. The severe weather knocked out numerous electrical distribution circuits and damaged eighteen transmission lines. No Transmission customers were out of service at 4:30 PM. The majority of remaining customers were restored late March 9. By March 10 AM, 2,800 customers remained without service and all are estimated to be restored by end of March 10.	N	Y		Y	
3/12/2006 20:30	39.5	City Water, Light & Power, Sprinfield IL	FRO	Y	Y	Y	UO	69,000	200	Weather - Tornado	On March 12, 2006 high winds, storms and two significant tornados interrupted the power to between 64,500 to 69,000 customers. Transmission lines of 38 to 138 kV were disrupted and severing the interconnection to a neighoring utility. Four coal generating units, 249 MW total, were also forced out of service. Restoration work began immediately following the passing of the tornados. The generating units were put into service by the following morning. By noon of March 14th, approximately 80% of the affected customers were restored.	Y	Y		Y	5,293

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3/16/2006 17:00	4.0	Pacific Gas & Electric - San Jose area	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Surveillance - Physical	At 5 PM, March 16, 2006, an employee observed a male subject acting suspiciously near a 115 kv transmission tower near the utilities facility offices. After the subject departed, the employee examined the support leg of the transmission tower and observed a metal rod which appeared to have been inserted or attached to the tower. Further examination located two additional bolts on other towers in the vicinity. Local law enforcement responded and extracted the bolts. No evidence of explosives were found. One bolt had been fashioned to store a piece of paper with writing which appeared to be in some sort of code. At 9 PM, the incident and location were determined to be safe and secure. The matter is being pursued by the appropriate law enforcement. There were no disruption of service.	N	N	No FIRM demand interruption reported	Y	
3/17/2006 21:08	N/A	Alberta Electric System Operator (AESO)	WECC-NWPP	Y	N	N	UO	N/A	650	Weather - Ice Fog	At 9:08 PM a 500 kV line relayed to lockout and a 240kV breaker opened. The area was experiencing ice fog at the time, and ice formation on the transmission lines is the suspected cause of the line loss and 650 MW of firm load.	N	Y		Y	
3/18/2006 15:29	46.0	Los Angeles Department of Water and Power, PacifiCorp East	WECC-CAMX	Y	N	N	UO	N/A	N/A	Equipment Failure - Fire	At 3:18 PM, a power plant received a third harmonic alarm on Filter Bank 2. At 3:22 PM, the power plant operator manually tripped the harmonic filter branch of Filter Bank 2 due to equipment fire. At 3:24:02 PM, the power plant operator manually tripped the entire Filter Bank 3 and at 3:24:47 PM manually tripped the entire Filter Bank 1 due to equipment fire. At 3:28 PM, the power plant operator manually tripped the remainder of Filter Bank 2. At 3:28:38 PM the "loss of filter trip timer" that trips the HVDC in 30 seconds was initiated. At 3:28:49 PM, system protection removed from service a generating unit in an adjacent system by a third harmonic differential scheme. At 3:29:08:943 PM and 3:29:08:947 PM, system protection removed from service HVDC Poles 1 and 2 respectively. At 3:29:09 PM, system protection removed from service generating unit #2 tripped by a remedial action scheme and was left out of service due to a boiler tube leak. This generating unit did not return until 1:32 PM on 3/20/06. The generating unit in the adjacent system was restored by 0:40 am on 3/19/06. The HVDC transmission line was returned to service at 0:35 am on 3/19/06. There were no electric customers interrupted because of this event.	N	N	No FIRM demand interruption reported	Y	
3/20/2006 7:55	0.1	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Intrusion, Lock Broken	On March 20, 2006, a Substation Operator found damaged/cut lock on a 100 kV transmission switch. The damage lock was removed, the switch locking mechanism was inspected, and a new lock was installed.	N	N	No FIRM demand interruption reported	Y	
4/8/2006 4:00	32.0	Southern Company.; North and Central Alabama and Northern Georgia Areas	SERC-Southern	Y	N	N	INT	115,589	300	Weather - Tornados, Thunderstorms	Severe thunderstorms and tornado in the service area affected 115,589 customers and approximately 300 MW of demand.	Y	Y		Y	6,432
4/14/2006 11:12	70.9	Public Service Company of New Mexico	WECC-AZNMSNV	Y	N	N	UO	N/A	N/A	Surveillance - Email	On April 17, Power Operations was notified by a customer service representative that an email inquiry was received on April 14 requesting information about "maintaining ... switchgears (GIS)" at the subject utility. The inquiry was sent to the utilities website general contact email ID. A verbal conversation between the utility representative and the sender of the email resulted in no reason for this out-of-state person to need the information. The utilities email response was sent on April 17. The utilities response stated that it did not provide that type of information, for security reasons. Immediately following that, a second inquiry for the same information was again made by the initial requestor. The utility again responded via email that it would not provide the requested information. The utility alerted its call center personnel of the issue and notified DOE and the ESISAC that an individual had attempted to gather information on the utilities operations.	N	N	No FIRM demand interruption reported	Y	
4/17/2006 15:25	4.6	Electric Reliability Council of Texas (ERCOT)	ERCOT	Y	Y	N	INT	200,000	1,000	Weather - High Temperatures, Limited Resources	On April 17, unseasonably warm temperatures (90's throughout the area) caused a large increase in electric demand. Due to the time of year, planned transmission and generation outages are underway further stressing system conditions. As the temperatures and loads continued to increase, all available generation was ordered on-line by the area control center (ACC). At 3:25 PM, the ACC implemented step 1 of a predetermined electric emergency curtailment plan (Plan). At 3:34 PM, the Plan was advanced to step 2 and the ACC ordered shedding of Firm and any Interruptible load. At 4:13 PM, as frequency continued to decline, the ACC step 4 of the Plan and ordered the interconnected utilities in the area to shed 1,000 MW's of firm load. At 5:31 PM, after the peak period for the area, the ACC advised the interconnected area utilities that they could begin restoring firm load. By 6:10 PM, all 1,000 MW's of the previously shed firm load was restored.	Y	N	Capacity Issue	Y	3,071

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
4/17/2006 16:10	2.0	CenterPoint Energy System-wide greater Houston Metro area (and across ERCOT)	ERCOT	Y	Y	N	INT	68,000	260	Weather - High Temperatures, Limited Resources	Common Description of Incident: On April 17, unseasonably warm temperatures (90's throughout the area) caused a large increase in electric demand. Due to the time of year, planned transmission and generation outages are underway further stressing system conditions. As the temperatures and loads continued to increase, all available generation was ordered on-line by the area control center (ACC). At 3:25 PM, the ACC implemented step 1 of a predetermined electric emergency curtailment plan (Plan). At 3:34 PM, the Plan was advanced to step 2 and the ACC ordered shedding of Firm and any Interruptible load. At 4:13 PM, as frequency continued to decline, the ACC step 4 of the Plan and ordered the interconnected utilities in the area to shed 1,000 MW's of firm load. At 5:31 PM, after the peak period for the area, the ACC advised the interconnected area utilities that they could begin restoring firm load. By 6:10 PM, all 1,000 MW's of the previously shed firm load was restored. Specific Utility Action: At the request of the ACC, the subject utility shed 260 MW of firm load within its service territory. This was done by a rolling blackout of specific circuits for a period of 15 minutes. A total of thirty-four circuits were removed from service, affecting approximately	Y	N	Capacity Issue	Y	351
4/17/2006 16:10	3.2	TXU Energy Delivery North and East Texas	ERCOT	Y	Y	N	INT	489,478	380	Weather - High Temperatures, Limited Resources	Common Description of Incident: On April 17, unseasonably warm temperatures (90's throughout the area) caused a large increase in electric demand. Due to the time of year, planned transmission and generation outages are underway further stressing system conditions. As the temperatures and loads continued to increase, all available generation was ordered on-line by the area control center (ACC). At 3:25 PM, the ACC implemented step 1 of a predetermined electric emergency curtailment plan (Plan). At 3:34 PM, the Plan was advanced to step 2 and the ACC ordered shedding of Firm and any Interruptible load. At 4:13 PM, as frequency continued to decline, the ACC step 4 of the Plan and ordered the interconnected utilities in the area to shed 1,000 MW's of firm load. At 5:31 PM, after the peak period for the area, the ACC advised the interconnected area utilities that they could begin restoring firm load. By 6:10 PM, all 1,000 MW's of the previously shed firm load was restored. Specific Utility Action: At the request of the ACC, the subject utility was requested to shed 380 MW of firm load within its service territory. AT 6:10 PM, the ACC requested that all operations be resumed including all firm load. The utility resumed normal operations at 7:20 PM.	Y	N	Capacity Issue	Y	806
4/17/2006 16:12	2.0	Lower Colorado River Authority, State of Texas (Central Texas)	ERCOT	Y	Y	N	INT	N/A	N/A	Weather - High Temperatures, Limited Resources	Common Description of Incident: On April 17, unseasonably warm temperatures (90's throughout the area) caused a large increase in electric demand. Due to the time of year, planned transmission and generation outages are underway further stressing system conditions. As the temperatures and loads continued to increase, all available generation was ordered on-line by the area control center (ACC). At 3:25 PM, the ACC implemented step 1 of a predetermined electric emergency curtailment plan (Plan). At 3:34 PM, the Plan was advanced to step 2 and the ACC ordered shedding of Firm and any Interruptible load. At 4:13 PM, as frequency continued to decline, the ACC step 4 of the Plan and ordered the interconnected utilities in the area to shed 1,000 MW's of firm load. At 5:31 PM, after the peak period for the area, the ACC advised the interconnected area utilities that they could begin restoring firm load. By 6:10 PM, all 1,000 MW's of the previously shed firm load was restored. Specific Utility Action: At the request of the ACC, the subject utility was requested to shed 49 MW of firm load within its service territory. This was done by a rolling blackout of specific circuits for a period of 15 minutes. The number of customers affected is unknown. At 6:10 PM, the ACC requested that all operations be resumed including all firm load. The utility resumed normal operations at 6:15 PM.	N	N	Capacity Issue	Y	
4/17/2006 16:20	2.2	Austin Energy	ERCOT	Y	Y	N	INT	8,000	40	Weather - High Temperatures, Limited Resources	Common Description of Incident: On April 17, unseasonably warm temperatures (90's throughout the area) caused a large increase in electric demand. Due to the time of year, planned transmission and generation outages are underway further stressing system conditions. As the temperatures and loads continued to increase, all available generation was ordered on-line by the area control center (ACC). At 3:25 PM, the ACC implemented step 1 of a predetermined electric emergency curtailment plan (Plan). At 3:34 PM, the Plan was advanced to step 2 and the ACC ordered shedding of Firm and any Interruptible load. At 4:13 PM, as frequency continued to decline, the ACC step 4 of the Plan and ordered the interconnected utilities in the area to shed 1,000 MW's of firm load. At 5:31 PM, after the peak period for the area, the ACC advised the interconnected area utilities that they could begin restoring firm load. By 6:10 PM, all 1,000 MW's of the previously shed firm load was restored. Specific Utility Action: At the request of the ACC, the subject utility was requested to shed 37-40 MW of firm load within its service territory. This was done by a rolling blackout of specific circuits for a period of 10 to 15 minutes, affecting a total of approximately 8-10,000 customers. At 6:10 PM, the ACC requested that all operations be resumed including all firm load. The utility resumed normal operations at 6:30 PM.	Y	N	Capacity Issue	Y	58

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
4/17/2006 16:35	2.4	American Electric Power / Texas Central/Texas North	ERCOT	Y	Y	N	INT	51,404	58	Weather - High Temperatures, Limited Resources	Common Description of Incident: On April 17, unseasonably warm temperatures (90's throughout the area) caused a large increase in electric demand. Due to the time of year, planned transmission and generation outages are underway further stressing system conditions. As the temperatures and loads continued to increase, all available generation was ordered on-line by the area control center (ACC). At 3:25 PM, the ACC implemented step 1 of a predetermined electric emergency curtailment plan (Plan). At 3:34 PM, the Plan was advanced to step 2 and the ACC ordered shedding of Firm and any Interruptible load. At 4:13 PM, as frequency continued to decline, the ACC step 4 of the Plan and ordered the interconnected utilities in the area to shed 1,000 MW's of firm load. At 5:31 PM, after the peak period for the area, the ACC advised the interconnected area utilities that they could begin restoring firm load. By 6:10 PM, all 1,000 MW's of the previously shed firm load was restored. Specific Utility Action: At the request of the ACC, the subject utility was requested to shed 58 MW of firm load within its service territory. This was done by a rolling blackout of specific circuits, affecting a total of approximately 51,404 customers. At 6:10 PM, the ACC requested that all operations be resumed including all firm load. The utility resumed normal operations at 7 PM.	Y	N	Capacity Issue	Y	94
4/24/2006 16:45	N/A	Tacoma Power - City of Tacoma, Cowlitz Substation / Southeast Tacoma	WECC-NWPP	Y	N	N	N/A	N/A	N/A	Vandalism - Copper Theft	On April 24, 2006 at 4:45 PM, Substation Operators arriving at the substation and noticed a disruption in the contour of the ground in the area of several 110 KV switch towers. After inspection, they found many of the equipment grounds had been cut from the towers and oil circuit breakers, and the ground mats had been pulled up and cut. Two holes were discovered in the fence where the suspects apparently entered and exited. A utility van used to filter oil was also broken into. In total, about 44 pounds of copper cable were removed from the towers and 6 grounds were removed from circuit breakers. Repairs are underway and will be completed shortly. No suspects were found.	N	N	No FIRM demand interruption reported	Y	
5/1/2006 13:00	N/A	PacifiCorp"	WECC-NWPP	Y	N	N	N/A	N/A	N/A	Vandalism - Copper Theft	The OE417 report filed on the vandalism of copper at a substation was filed in error. After further investigation of the May 1 incident, it was found that the substation was not vandalized and no theft had occurred. It was discovered that the substation was an abandoned privately owned organization. The organization property happened to be adjacent to the utilities substation property, thus the confusion and erroneous report. The utilities substation was not being utilized and the utility owned equipment was not energized nor was it capable of being in service.	N	N	No FIRM demand interruption reported	Y	
5/2/2006 12:31	0.5	Bonneville Power Administration, Los Angeles Department of Water and Power	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Equipment Failure - Transmission Line Fault	Prior to the May 2nd incident, the system was operating normally and there were no unusual or abnormal weather conditions. At approximately 12:31 PM a line fault occurred. Within the total transmission path, the MW's being transmitted were reduced to less than 70%. The fault initiated a Remedial Action Scheme which automatically changed the scheduled flows in the area. Maximum frequency deviation due to this operation was from 59.99 Hz to 59.9455 Hz which recovered to normal at 12:33 PM. A directive was released by the areas Reliability Coordinator to take all necessary actions, up to and including, shedding firm load to unload the affected transmission path and recover ACE. At 12:50 PM, operations along the transmission path were sufficiently unloaded and NO generation and/or Firm load were shed. The frequency returned to normal at 1:01 PM. The reason for the fault continues to be investigated.	N	N	No FIRM demand interruption reported	Y	
5/3/2006 15:30	3.7	Pacific Gas & Electric - City of Bakersfield area	WECC-CAMX	Y	Y	N	UO	55,655	300	Equipment Failure - Transformer Failure	At 3:30 PM on May 18, a 115 kV bus potential transformer at a power station failed and a fire occurred. Protective relays opened the 115 kV and two 230/115 kV transformer banks connected to the power station. Approximately 300 MW of load demand and 55,655 customers were affected. By 4:54 the two 230/115 kV busses were restored to operations and the 115 KV busses were restored to operation at 4:55 PM. All load was restored by 7:10 PM and final restoration of all affected customers was completed by 9:35 PM.	Y	Y		Y	737
5/4/2006 19:36	0.9	Entergy Corporation	SERC-Entergy	Y	N	N	UO	N/A	N/A	EMS Computer Failure - Hard Drive	The utilities Transmission Operations Center (TOC) experienced an EMS computer system failure of their primary and backup systems at 7:36 CST on May 4, 2006. This outage caused the VShed protection scheme to be inactive until the computer problem was resolved. The cause of the computer outage was an "Unknown Host System Software Lockup". It was not found to be related to any network, host system hardware, database, operator action, SCADA Support action, or any other area other than the core Host System Software.	N	N	No FIRM demand interruption reported	Y	
5/12/2006 10:35	26.3	Bangor Hydro-Electric Company / Northern Maine and the Maritimes	NPCC-ISO-NE	Y	Y	N	UO	N/A	N/A	Vandalism - Copper Theft	Several substations were discovered to have been broken into. The only identified vandalism was the removal/theft of grounding copper wires. The repairs required that a 345 kV power line be taken out of service for a period of approximately 8 hours. Within 24 hours, all services had been repaired and returned to normal. No load demands or customers were affected.	N	N	No FIRM demand interruption reported	Y	
5/19/2006 17:05	0.2	Southern Company	SERC-Southern	Y	N	N	UO	N/A	N/A	Surveillance - Telephone	The system operations center of a utility received a suspect telephone call. The person requested operating information and became indigent when that was refused. A caller ID was obtained and the utilities security and local authorities were contacted.	N	N	No FIRM demand interruption reported	Y	
5/25/2006 10:50	1,489.2	CINERGY-Duke Energy Ohio	RFC	Y	Y	Y	UO	112,000	800	Weather - High Winds, Storms, Lightning	Major storms including high winds and lightning moved through the service area causing local or regional power outages. The affected utility activates its emergency response and organized its restoration efforts accordingly.	Y	Y		N	798,193

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6/1/2006 16:39	3.4	Dominion – Virginia Power / North Carolina Power	SERC	Y	Y	N	UO	N/A	N/A	Cyber - Unknown	At 4:39 PM of June 1, 2006 the Energy Management System and Distribution Management System networks at the System Operations Center became isolated from the rest of the enterprise network. Preliminary investigations suggest an equipment malfunction resulting in an internal network routing issue or a computer network bridge loop; possibly a network or firewall related problem. Investigations continue on the cause of the problem. Configuration changes have been implemented and the network is stable. Operations were relocated to the Emergency System Operations Center. Restoration of normal computer network operations was achieved at approximately 8:00 PM on June 1 with normal system operations returning to the primary System Operations Center. There was no effect on power system adequacy.	N	N	No FIRM demand interruption reported	Y	
6/1/2006 18:00	39.0	PECO Energy	RFC	Y	Y	N	UO	111,555	N/A	Weather - Thunderstorms, Lightning	At 6:00 PM on June 1 heavy rains, hail and lightening came into the utilities area resulting in outages for approximately 60,000 customers. The estimated restoration time for all customers was estimated at 6:00 PM on June 2. Less than 24 hours after the initial storm, at 4:00 PM on June 2, a second series of thunderstorms (classified as "Severe" by the National Weather Service) moved through the service territory initially affected and surrounding areas. Heavy rains, winds and lightening continued for several hours resulting in outages of an additional 50,000 customers being out of service. All total, 111,555 customers were affected by the series of storms. The utilities Emergency Operations Center (EOC) was activated to oversee all response activities including assistance from a neighboring utility, through our pre-established mutual assistance process, and contract support. The customer response efforts were 9:00 am and normal system operations were enacted at 3:00 PM June 3rd.	N	Y		Y	
6/4/2006 12:34	3.4	Platte River Power Authority Tri-State Generation and Transmission Association	WECC-PMPA	Y	N	N	UO	31,076	130	Equipment Failure - Transmission Line Fault	Prior to the incident, the utility had scheduled and taken a line, 115 kV, out of service to replace several CCVT (Closed Coupling Voltage Transformer) that were leaking oil. A risk analysis was done prior to the equipment repair. The analysis also determined what line outages and voltage reductions would be necessary should an incident occur during the repair. At 12:34 PM on the day of the scheduled repair, a line in the immediate area of the repair relayed out of service (trip) for an as yet unknown reason. Because of the repair, voltages in the area dropped significantly and shed 26 MW of customer load. The neighboring utility immediately implemented manual load shedding, dropping 50 MW, as predetermined. All total, 130 MW of load was eventually shed. At 1:18 PM the line that experienced the lightning strike was returned to service and voltage in the area returned to above nominal levels. At the utility where the incident initiated, all load was restored by 2:34 PM. Load restoration by neighboring began at 1:27 PM and was completed at 3:55 PM.	Y	Y		Y	292
6/4/2006 12:34	0.7	Western Area Power Administration	WECC-PMPA	Y	N	N	VR	N/A	N/A	Equipment Failure - Transmission Line Fault	At the time of the inciden, the transmission system was in an abnormal state because of a scheduled line outage. A transmission line equipment failure at 12:34 PM resulted in line loading reconfigurations and temporary voltage reductions. Operations of affected lines, including voltages, were returned to normal at 1:18 PM.	N	N	No FIRM demand interruption reported	Y	
6/8/2006 16:00	0.5	Tacoma Power - City of Tacoma, Cowlitz Substation / Southeast Tacoma	WECC-NWPP	Y	N	N	UO	N/a	N/A	Vandalism - Intrusion	On June 8, 2006 at 4 PM, during a substation inspection, Substation Operators found a hole cut in the fence. The hole was big enough to provide entry by person(s). The hole was temporary repaired, a permanent fix will take place soon. The inspection found all equipment to be in good condition.	N	N	No FIRM demand interruption reported	Y	
6/13/2006 12:00	N/A	Public Service Company of New Mexico	WECC-AZNMSNV	Y	N	N	UO	N/A	N/A	Surveillance - Physical	A facility employee noticed an automobile parked parallel to the entrance thus blocking the main gate. When approached, the vehicle pulled away down a dirt road leading to the highway. The car and its occupants had no known relationship to the facility.	N	N	No FIRM demand interruption reported	Y	
6/14/2006 8:51	1.9	Entergy Corporation	SERC-Entergy	Y	N	N	UO	1,081	7	Vandalism - Copper Theft	A 138 kV line tripped, upon investigation it was found that someone tried to steal a pole ground (copper) by attaching a truck to it and pulling it off the pole. The damage was repaired and the ground replaced.	N	Y		Y	9
6/14/2006 21:45	0.8	Alberta Electric System Operator (AESO) British Columbia Transmission Company (BCTC)	WECC-NWPP	Y	N	N	UO	N/A	N/A	Weather - Lightning - Islanding	Lightning struck a 500 kV line at 9:45 PM on July 4, 2006 causing it to relay and the utility system separate its connections to neighboring utilities. The utility experienced separation (islanding). The islanding resulted in the loss of 80 MW of load; although no customers were affected by the separation. At 10:07 PM, the 500 kV line was synchronized with neighboring utilities and at 10:35 PM all affected transmission lines were in service... Lightning and heavy rains continued in the area but did not affect the transmission system.	N	N	No FIRM demand interruption reported	Y	

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6/26/2006 19:37	1.0	ISO-New England	NPCC-ISO-NE	Y	Y	N	UO	30,000	115	Equipment Failure - Lightning Arrestor	At 7:37 PM on June 26th, a lightning arrester at a substation failed and tripped a 115 KV line. The 115 kV alternate service line was out of service for scheduled maintenance at the time of the incident. Approximately 115 MW of load was lost and 30,000 customers lost power. The line, along with the 30,000 customers, was restored to service at 8:40 PM. NOTE: The initial report was sent out assuming more than 50,000 customers lost power during the transmission outage. Actually, the number of customers that lost power was approximately 30,000 customers. Therefore, the initial report filing was not necessary in accordance with the OE-417 guidelines. Restoration of normal computer network operations was achieved at approximately 8:00 PM on June 1 with normal system operations returning to the primary System Operations Center. There was no effect on power system adequacy.	Y	Y		Y	81
6/30/2006 9:02	0.0	Pacific Gas & Electric	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Human Error - Technical Error	A substation technician was testing modifications and technician mistakenly sent incorrect line outage indications to the neighboring 500 kV system, which detected a triple line outage at 9:02 am. No actual line outages occurred. When the line outages were detected, the protection system immediately issued transfer trip signals that resulted in the dropping of the generators feeding the 500 kV line, 1,312 MW. The test error was cleared at 9:03 am.	N	N	No FIRM demand interruption reported	Y	
6/30/2006 13:08	212.9	Tennessee Valley Authority	SERC-TVA	Y	N	N	UO	N/A	N/A	Sabotage - Substation	On Friday June 30, 2006 at 1:08 PM a utility discovered physical break-ins at two separate 161 kV substations. No electrical system damage was done at one substation. At the second substation, an oil drain valve on an oil circuit breaker was found opened in an apparent act of sabotage. The breaker had been removed from service prior to the equipment damage. The initial investigation has been completed with a report is pending. Both substations have been re secured and the environmental remediation's have been completed.	N	N	No FIRM demand interruption reported	N	
7/2/2006 12:00	7.1	Entergy Corporation	SERC-Entergy	Y	N	N	UO	N/A	N/A	Weather - Lightning	At noon, a lightning strike caused the loss of the server air conditioner at the transmission operations center. This then resulted in the outage of the EMS computer system and a portion of the voltage shedding protection system. The matter was resolved and all operations returned to normal at 7:05 PM.	N	N	No FIRM demand interruption reported	Y	
7/4/2006 3:47	0.2	Alberta Electric System Operator (AESO)□ British Columbia Transmission Company (BCTC)	WECC-NWPP	Y	N	N	UO	N/A	N/A	Weather - Lightning - Islanding	Lightning struck a 500 kV line at 3:47 PM causing it to relay and the utility system to separate its connections to neighboring utilities. The utility experienced separation (islanding). The islanding resulted in the loss of 150 MW of load: although no customers were affected by the separation. At 3:56 PM, the 500 kV line was synchronized with neighboring utilities. Lightning continued in the area but did not affect the transmission system.	N	N	No FIRM demand interruption reported	Y	
7/4/2006 17:30	2.8	Dominion - Virginia Power/North Carolina Power	SERC	Y	Y	N	UO	67,000	335	Weather - Thunderstorms	Severe thunderstorms went across the state Tuesday night, July 4th. Normal storm restoration procedures were applied.	Y	Y		Y	628
7/5/2006 9:00	27.0	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	Upon arrival, on July 5, 2006, the utility work crew found that the substation fence had been cut and that some copper bus material had been stolen. The copper bus had been removed from service and placed near the control house in an inconspicuous place. A further inspection of the substation revealed no other damage or theft. The hole in the fence was made secure and permanent repairs are being arranged.	N	N	No FIRM demand interruption reported	Y	
7/5/2006 23:30	0.2	Alberta Electric System Operator (AESO)□ British Columbia Transmission Company (BCTC)	WECC-NWPP	Y	N	N	UO	N/A	N/A	Weather - Lightning - Islanding	Lightning struck a 500 kV line at 11:30 PM on July 5, 2006 causing it to relay and the utility system to separate its connections to neighboring utilities. The RAS (Remedial Action Scheme) tripped the designated related transmission lines. As a result, the utility experienced separation (islanding). The islanding resulted in NO loss of load and NO customers were affected. At 11:39 PM, the 500 kV line was synchronized and by 11:42 PM the last lines were synchronized.	N	N	No FIRM demand interruption reported	Y	
7/5/2006 23:30	0.2	British Columbia Transmission Company (BCTC), Alberta Electric System Operator (AESO)	WECC-NWPP	Y	N	N	UO	N/A	N/A	Weather - Lightning - Islanding	Lightning struck a 500 kV line at 11:30 PM on July 5, 2006 causing it to relay and the utility system to separate its connections to neighboring utilities. The RAS (Remedial Action Scheme) tripped the designated related transmission lines. As a result, the utility experienced separation (islanding). The islanding resulted in NO loss of load and NO customers were affected. At 11:39 PM, the 500 kV line was synchronized and by 11:42 PM the last lines were synchronized.	N	N	No FIRM demand interruption reported	Y	
7/18/2006 12:10	52.3	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	On July 18, it was discovered that the switchyards fence had been cut and removed. Upon inspection of the switches, it was found that the copper grounds had been removed from all switches and towers in the immediate vicinity of the switchyard. The estimated completion date to replace the grounds is July 20.	N	N	No FIRM demand interruption reported	Y	
7/18/2006 19:00	N/A	PECO Energy	RFC	Y	Y	N	UO	380,000	N/A	Weather - High Winds, Storms	At 7 PM on July 1, 2006, a storm with wind gusts of up to 70 MPH came into the utilities service territory resulting in outages for approximately 380,000 customers. The estimated restoration time for all storm related outages is currently unknown. Due to the amount of customers impacted this will be a multi-day restoration.	N	Y		Y	
7/18/2006 20:07	2.4	ISO-New England□ Norwalk Stamford Connecticut	NPCC-ISO-NE	Y	Y	N	UO	N/A	N/A	CORRECTION-/NONE INCIDENT	NONE INCIDENT - This incident does not meet the minimum reporting criteria for OE417 and thus should not have been reported to DOE.	N	N	No FIRM demand interruption reported	Y	

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7/19/2006 11:00	6.9	Entergy Corporation; Greater Little Rock, AR Area within Entergy Arkansas Grid	SERC-Entergy	Y	N	N	PA	8,000	40	Equipment Failure - Transformer Failure	On July 19, an unplanned outage of a single phase 500/115 kV A transformer resulted in low voltage and overload. The cause of the transformer trip was a ruptured oil storage tank. Public appeals were made requesting the conservation of energy.	N	N	Public Appeal	Y	185
7/19/2006 19:00	278.0	Ameren Corp., St Lousi, MO area	SERC	Y	Y	Y	UO	600,000	1,500	Weather - Thunderstorms, Lightning	Thunderstorms, with wind exceeding 90 MPH ,with high levels of lightning occurred on July 19, 2006. The high winds and falling trees did significant damage to the distribution system. At one point, 600,000 customers in were without service. By July 26, restoration efforts to the electrical infrastructure continued and was not expected to be completed until July 29. Restoration crews from 11 states are participating in the repair efforts. which caused additional outages. Ameren Corporation is being supported by utility repair crews from 11 other states. As of July 26, a total of 96,353 remain without power.	Y	Y		N	279,390
7/22/2006 13:09	122.8	Pacific Gas & Electric	WECC-CAMX	Y	Y	N	PA	1,271,893	200	Weather - High Temperatures	Beginning on Monday July 17 and lasting through Wednesday July 26, the western US experienced a widespread heat wave. Record or near record temperatures spread over the entire service territory except for coastal areas. Many areas set either all-time high record temperatures or exceeded records for consecutive days with temperatures above 100 degrees F. Although there had been a number of heat-related outages since the beginning of the heat wave, the numbers were small until the extreme peak temperatures hit the area on July 22. Throughout the day on July 22, numerous heat-realated distribution problems arose and continued to be a major problem until July 25. More than 1,270,000 customers have had power interrupted at one time or another. The primary cause is due to the overheating of some 1,207 transformers - mostly distribution pole-top and pad-mount transformers.	N	Y		N	16,462
7/24/2006 14:33	6.5	California Independent System Operator (CAISO),PG&E, SCE, and SDG&E	WECC-CAMX	Y	Y	N	PA	N/A	855	Weather - High Temperatures	At 10 am the areas Reliability Coordinator declared a Stage 1 alert due to high temperatures and demand. At 1 PM this was increased to Stage 2.. At 2:33 PM, the Reliability Coordinator called for the shedding of 855 MW of non-firm interruptible customers to reduce the load curve and preserve Operating Reserves. Specific loads were identified for selected utilities. Other actions taken included making public appeals and implementing a warning, alert, or contingency plan. At 5:33 PM, all interrupted loads were restored. At 6:14 PM, the Stage 2 was downgraded to Stage 1. The Stage 1 was terminated at 9 PM.	N	Y		N	3,695
7/24/2006 14:33	6.0	Southern California Edison Company (SCE)	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Weather - High Temperatures	At 10 am on July 24, 2006 the areas Reliability Coordinator declared a Stage 1 alert due to high temperatures and demand. At 1 PM this was increased to Stage 2.. At 2:33 PM, the Reliability Coordinator called for the shedding of 504 MW of Interruptible Tariff Rate load at the subject utility to reduce the load curve and preserve Operating Reserves. The subject utility shed an estimate 414 MW of interruptible load. Other actions taken included making public appeals and implementing a warning, alert, or contingency plan. At 5:33 PM, all interrupted loads were restored. At 6:14 PM, the Stage 2 was downgraded to Stage 1. The Stage 1 was terminated at 9 PM.	N	N	No FIRM demand interruption reported	N	
7/24/2006 15:28	0.4	British Columbia Transmission Corporation (BCTC), Alberta Electric System Operator (AESO)	WECC-NWPP	N	N	N	UO	0	650	Weather - Lightning - Islanding	Pre-disturbance, there were reports of lightning and thunderstorms in the area. A neighboring system was in a NERC Energy Emergency Alert Level 2 because of 800 MW of generation outages.. About 3:28 PM, the 500-kV line relayed due to a lightning strike and the control systems tripped a 138-kV line. This separated the adjacent system from the Interconnection. The control system then tripped 525 MW of generation at the initiating utility causing its frequency to decreased to 59.839 Hz from 60.007 Hz. No customer load was interrupted in the utility where the trip was initiated. A neighboring systems frequency dropped to 59.13 Hz, causing the Under-Frequency Load Shedding Scheme of 250 MW of customer load. About 3:33 PM, the neighboring utility declared an EEA Level 2, Alert 3 and issued a verbal directive to shed 400 MW of firm load. At 3:44 PM, the tripped 500-kV and 138-kV lines were returned to service. Subsequently, at 3:54 PM all loads, including that at the neighboring utility, were restored.	Y	Y		Y	189
7/24/2006 15:28	N/A	Bonneville Power Administration	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Equipment Failure - Transmission Line Fault	On July 24, 2006 at 3:28:32 PM, the line faulted and tripped to lockout. Prior to the incident the utilities transmission system was operating normally and there were no unusual or abnormal weather conditions. The transmission control system's Remedial Action Scheme (RAS) properly issued protective generator dropping 1,661 MW of generation, insertion of other predetermined protection schemes (braking resistors and shunt capacitors). Oscillations were noted on the system and those oscillations were dampened within 30-40 seconds. All generation was restored by 3:46 PM and no customer load was interrupted as a result of the event. NOTE: A transmission outage that occurred about the same time at a neighboring system was not the cause or result of this event described herein.	N	N	No FIRM demand interruption reported	Y	

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Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
7/25/2006 16:12	0.2	Alberta Electric System Operator	WECC-NWPP	Y	N	N	UO	N/A	N/A	Weather - Lightning - Islanding	Predisturbance system operating conditions were normal. The weather conditions included heavy lighting and rain. Due to lightning strikes in the area, at 4:12 PM the 500 kV Line relayed due to lightning causing the utility to separate from the Interconnection. As a result of the relaying, a secondary 138 kV also relayed out. The frequency then went from 60.014 to 60.024. The Interconnection was delivering 250 MW at time of the line trip. However, no customers were affected and no customer demand was lost. At 4:23 PM, the connection to the Interconnection was synchronized.	N	N	No FIRM demand interruption reported	Y	
7/27/2006 19:00	76.0	PECO Energy: Chester, Montgomery, Delaware, Philadelphia, and Bucks County	RFC	Y	Y	N	UO	175,000	N/A	Weather - Thunderstorms	The utyilities service territory experienced several waves of thunderstorms. Beginning Thursday, July 27, 2006; during the overnight hours, about 90,000 customers lost service, primarily due to severe lightning. At 4 PM, Friday, another wave of storms with violent winds and heavy rains hit the service territory resulting in another 85,000 customer outages. The utilities Emergency Operations Center and all Regional Storm Centers were activated to coordinate restoration activities. The utilities crews worked through the weekend to return customers to service. As a result, all storm related customer outages were restored by 11:15 PM on Sunday, July 30.	N	Y		Y	
8/1/2006 10:47	6.7	Midwest ISO's East and Central Regions: ALTE, AMRN, CIN, CILC, CWLD, CWLP, FE, HE, IP, IPL, LGEE, MECS, MGE, NIPS, SIGE, SIPC, UPPC, WEC, WPS	MRO	Y	Y	Y	PA	N/A	N/A	PA - Weather, High Temperatures	The Reliability Coordinator declared a regional Energy Emergency Alert 2 event effective immediately. The reason for this was the extremely high temperatures, peak loads, generation availability, and system conditions occurring today, Tuesday, August 1, 2006. Specific participants of the region and its sub-region were requested to enact NERC EEA Level 2, this includes: • Curtailment of non-firm energy curtailments outside the market, • Public Appeals to reduce demand, • Voltage reduction where applicable, • Demand side management, • Utility load conservation measures, and • Interruption (shedding) of non-firm end use loads in accordance with applicable contracts.	N	N	Public Appeal	Y	
8/1/2006 12:00	7.0	First Energy Corp., Northern Ohio	MRO	Y	Y	Y	PA	N/A	N/A	PA - Weather, High Temperatures	The utility submitted a Public Appeal to reduce load after the Reliability Coordinator for the area declared an EEA Level 2 at 10:44 am. This EEA Level 2 was downgraded to EEA Level 1 at 5:38 PM, also on August 1.	N	N	Public Appeal	Y	
8/2/2006 12:00	4.7	Midwest ISO's Market sub-region: AMRN, CIN, CILC, CWLD, CWLP, FE, HE, IP, IPL, LGEE, MECS, NIPS, SIGE, SIPC.	MRO	Y	Y	Y	PA	N/A	N/A	PA - Weather, High Temperatures	The Reliability Coordinator declared a regional Energy Emergency Alert 2 event effective immediately. The reason for this was the extremely high temperatures, peak loads, generation availability, and system conditions occurring today, Tuesday, August 2, 2006. Specific participants of the region and its sub-region were requested to enact NERC EEA Level 2, this includes: • Curtailment of non-firm energy curtailments outside the market, • Public Appeals to reduce demand, • Voltage reduction where applicable, • Demand side management, • Utility load conservation measures, and • Interruption (shedding) of non-firm end use loads in accordance with applicable contracts.	N	N	Public Appeal	Y	
8/2/2006 13:00	5.0	New England area utilities, ISO-New England	NPCC-ISO-NE	Y	Y	N	VR	N/A	N/A	Weather - High Temperatures, Humidity	A generation capacity deficiency occurred on August 2nd due to a increased demand because of the regions high heat and high dew point. The Reliability Coordinator enacted NPCC OP#4, Level 12 which enacts a 5% region-wide voltage reduction. The OP#4, Action 12 was cancelled at 4:35 PM EST when the ambient temperatures and demand reduced.	N	N	Voltage reduction	Y	
8/3/2006 1:10	0.0	New England area utilities, ISO-New England	NPCC-ISO-NE	Y	Y	N	UO	11,000	40	Equipment Failure - Transmission, Vegetation	At approximately 01:10 hr of August 3, 2006, a 345 kV transmission circuit tripped. Indications are that the line protection sschemes did not properly clear the fault and the remote backup protection had to operate. That remote protection tripped resulting in the interruption of approximately 40 MW of load. The event caused the 115kV inter-area tie line to exceed its 15 minute emergency rating (STE) by 4 MVA for approximately one minute. The utilityy operator closed the circuits breaker at approximately one minute after the initial event and the another area breakers at approximately two minutes after the event. The breakers for the 345 kV line closed automatically at approximately twelve minutes after the event. All load was restored within approximately 3 minutes after the event. An aerial patrol did not reveal the reason for the trip. Fault recorder data suggests that a vegetation related fault developed on the line. The 345 kV transformer experienced a failed lightning arrester during this event and was out of service until approximately 2:00 PM that day. The 345 kV line was de-rated as a precaution until additional line patrols were completed. This measure is to preclude a vegetation related fault.	Y	Y		Y	1

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
8/10/2006 15:48	8.6	Alberta Electric System Operator (AESO)	WECC-NWPP	Y	N	N	UO	N/A	N/A	Weather - Lightning - Islanding	Prior to the disturbance system operating conditions were normal. The weather conditions included heavy lighting and rain. At approximately 3:48 PM, The 500 kV path was tripped, thus opening and separating the utility system from the Interconnection. The line relayed (tripped) due to lightning strikes. Tripping of the line resulted in the tripping of associated 138-kV lines. The frequency deviated from a predisturbance level of 60.0 Hz to a maximum deviation of 59.79 Hz and recovered to normal in 6 minutes. This occurred due the interruption of a transfer of 210 MW of energy that was being delivered to affected utility.. The 138-kV interconnection was re-established at 4:25 PM. At 6:16 PM the 138-kV interconnection tripped again due to lightning. At 6:25 PM, 290 MW of generation was lost while the utilities system was again separated from the Interconnection. This time the frequency fell to 59.56 Hz and recovered to normal in 4 minutes. No load was lost in the Interconnection or the affected utility during either of the separations. The 138-kV transmission lines were returned to service at ^;39 PM. The Interconnection was returned to service at 6:39 PM.PDT. The 500-kV transmission line was returned to service the next day at 0:22 am.	N	N	No FIRM demand interruption reported	Y	
8/19/2006 11:10	0.0	Hydro-Quebec, TransEnergie	NPCC-Quebec	N	Y	N	UO	N/A	N/A	Human Error - Misoperation	The operator, while switching generators to follow new schedules on the asynchronous tie, inadvertently synchronized the utilities system with the adjacent , but not synchronized interconnection. The two systems remained synchronized during 57 seconds before the operator opened a breaker. The supervisory control system (ADR) dedicated to minimize the risk of such events was unavailable when these events occurred.	N	N	No FIRM demand interruption reported	Y	
8/23/2006 9:30	2.8	Pacific Gas & Electric	WECC-CAMX	Y	Y	N	UO	8,000	N/A	Vandalism - Intrusion	At approximately 9:30 AM PDT on August 23, 2006, a 115 kV line relayed and caused the loss of service to about 8,000 customers. All service was restored by 12:16 PM that same day. Inspections established that the probable cause was tampering with equipment on a transmission pole located in a remote area. The switch was forced open by pulling or leveraging it past its locking device. The line is a parallel service line that was not energized at the time, so the damage was not discovered until after the line was put into service. The County Sheriff's Office has been notified and has assumed jurisdiction. No suspects have been identified and no similar incidents have occurred. The utility is treating this as an isolated act of vandalism.	N	N	No FIRM demand interruption reported	Y	
8/28/2006 9:00	N/A	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	Vandalism and theft of copper occurred during the weekend of 8/26-27 at a facility that was de-activated by the affected utility approx. 4-5 years ago. The facility now houses a satellite office hub for the utilities cable service and thus has a connection to the utilities distribution system. A minor amount of office load was disrupted and crews quickly restored all service. The local police are reviewing the vandalism/theft. The utility has increased its local security to provide coverage from 1600-0600, M-F and 24 hrs on weekends.	N	N	No FIRM demand interruption reported	Y	
9/1/2006 5:30	50.5	Progress Energy Carolinas, Inc.; Eastern North Carolina	SERC-VACAR	Y	N	N	UO	61,000	N/A	Weather - Tropical Storm Ernesto	On 9/1/2006 Tropical Storm Ernesto caused major distribution system interruptions (outages) in eastern North Carolina and the loss of service to a max of about 61,000 customers (7 am on 9/1). By 10 am that same day, there were about 39,000 customer outages. Full customer service restoration is anticipated by 8 am on 9/3.	N	Y		Y	
9/1/2006 6:41	64.3	Dominion – Virginia Power / North Carolina Power; Virginia and North Carolina	SERC-VACAR	Y	Y	N	UO	150,520	225	Weather - Tropical Storm Ernesto	On 9/1/2006, a Tropical Storm caused minor flooding and major distribution system interruptions and the loss of service to approximately 150,520 customers in the utilities service area. The utilities Storm Center contingency plans has been activated and electric service restorations are in progress. The storm is moving northward and is expected to exit the service territory later today (9/1). Crews continue to restore customers. The incident ended at 9/3 at 3:25 PM when customer outages dropped below 50,000. By 9/5, crews continue to restore the remaining 6200 customer outages.	Y	Y		Y	9,696
9/5/2006 9:45	6.8	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	On 9/5/2006, utility personnel found the gate locks cut at a de-energized substation where mobile 110 to 12.5 kV transformers were stored. Copper wire was removed. The matter has been referred to local authorities.	N	N	No FIRM demand interruption reported	Y	
9/5/2006 12:15	4.3	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	On 9/5/2006, roving substation operators found a perimeter fence cut and 20'-25' of 4/0 copper ground missing from each of the 230kV terminals. Crewa repaired the fence and install new grounds.	N	N	No FIRM demand interruption reported	Y	
9/5/2006 13:30	3.0	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	On 9/5/2006, utility personnel reported microwave tower grounds removed by vandals. The tower will be replaced.	N	N	No FIRM demand interruption reported	Y	
9/15/2006 17:45	3.7	City of Lake Worth Utilities	FRCC	Y	N	N	UO	26,894	81	Weather - Lightning Storm	On September 15, 2006, an outage occurred during a severe lightning storm. The outage was caused by two lightning strikes. One directly to the system operations center and the other to the internal 138 kV system. System operations lost the UPS and ATS for the emergency generator. The 138 kV system lost two ABB microsheild relays. All damaged equipment has been replaced and tested.	Y	Y		Y	200
9/16/2006 19:20	1.7	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Copper Theft	On September 16, 2006, substation personnel reported an access hole was cut into the south perimeter fence at the Southwest Substation. Surplus, non-connected, scrap copper materials were stored there. It is uncertain what was taken. Local authorities responded and are reviewing the incident.	N	N	No FIRM demand interruption reported	Y	

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9/21/2006 19:14	2.0	Southern Company	SERC-Southern	Y	N	N	UO	4,165	11	Vandalism - Substation/Physical Damage	On September 21, 2006, at a 230/23-kv Substation, suspects broke into the substation by cutting a lock off the gate. They then cut the switch house doorlock off, entered the switch house and cut out a section of the antenna cable feeding the radio. The DC power cable feeding the radio was also cut. This act caused a short which tripped the DC supply breaker feeding the RTU and radio. At about this same time, the Circuit Switcher feeding bank #1 was opened. The damages and changes were quickly corrected and investigation are continuing.	N	Y		Y	15
9/25/2006 8:30	5.0	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Break-In	On September 25, 2006 at 8:30 AM, utility personnel discovered an unauthorized entry into a substation and associated building. No visible entry point was detected; it is assumed suspects climbed over the fence and entered through a widow that was found broken in North personnel door of the building. There appears to have been an attempt to disable the internal building security system. No material thefts or damage have been detected. Repairs to the window and security system were made.	N	N	No FIRM demand interruption reported	Y	
9/28/2006 15:08	0.7	Electric Reliability Council of Texas (ERCOT)	ERCOT	Y	Y	N	INT	2	N/a	Special Protection	On September 28, 2006 at about 3:08 PM, a series of events occurred resulting in the activation of the circuits Special Protection Scheme. Due to a planned clearance of a 345 kV bus, higher than normal flow was observed on the affected circuit. Several generating units in the area were on-line and two steam turbines were in the process of ramping to 300 MW at 1:50 PM. This caused the affected 345 kV circuit to ramp up, reaching the 90% alarm load level at 2:10 PM. The line continued to load up until it exceeded 100%, arming the SPS at 3:06:40 PM. The two steam generating should have begun to ramp down, but this did not happened. At 3:08:43 PM, the 345 kV breaker tripped, by the SPS as intended, disconnecting the affected 345 kV bus. The 345 kV breaker was re-closed at 3:32 PM after clearance from the area control center. As a result of the incident, the frequency declined at two substation. This frequency dip triggered the shedding of 170 and 22 MW of interruptible load.	N	N	No FIRM demand interruption reported	Y	
10/2/2006 14:00	81.0	Commonwealth Edison -ELONnion – Virginia Power / North Carolina Power	RFC	Y	Y	N	UO	269,322	N/A	Weather - Thunderstorms	On October 2, 2006 sever thunderstoms with high winds and lightning in the Chicago area affected distribution system. Heavy conductor and pole damage from vegetation contributed largely to customer outages. The Storm Restoration Process was initiated. Neighboring utilities and contractors were brought in to supplement the repair forces. Approximately 269,322 customers were affected. By October 4, some 70,000 customers remained without electricity.	N	Y		Y	
10/2/2006 15:05	5.6	Southern California Edison Company (SCE)	WECC-CAMX	Y	Y	N	UO	130,000	308	Equipment Failure - Breaker	On October 2, 2006 at 3:05 PM, 308 MW of firm customer load on was interrupted when three substation banks (220/66 kV) each relayed on 66 kV local breaker failure backup protection. The action was the result of a significant fault occurring on the 66 kV subtransmission system. Approximately 130,000 customers were affected. Subsequent investigation determined that an unidentified individual started a small fire which then spread and burned under the 66 kV line, causing a flashover and the line to relay when overhead jumpers blew open as result of the fault. Firm load interrupted as result of system problem and load subsequently restored. The individual who started the fire was reportedly apprehended by local law enforcement agency.	Y	Y		Y	1,149
10/3/2006 17:28	4.5	Electric Reliability Council of Texas (ERCOT)	ERCOT	Y	Y	N	UO	100,308	185	Equipment Failure - CCVT	On October 3, 2006, at 5:28 PM a CCVT located between breakers A and B at generating facility switchward exploded and debris caused the station to trip. A 345KV bus and several 345/138 Auto Transformers and associated lines were forced out service. Approximately 1,223 MWs was taken out of service and frequency dropped to 59.832. At 5:35 PM Reliability Coordinator shed interruptable load to restore frequency. At 5:49 PM the local transmission operator shed partial distribution load due to transmission instability and voltage issues. At 5:55 PM additional load was requested off line maintain transmission system voltage. At 5:57 PM, the Reliability Coordinator was informed that the local transmission operator had started shedding load due to voltage instability. Approx. 185 MW of load was shed. By 9:58 PM, all load was restored.	Y	Y		Y	558
10/12/2006 17:48	258.2	Niagara Mohawk Power Corporation (dba National Grid)	NPCC-ISO-NE	Y	Y	N	UO	180,000	400	Weather - Snow Storm	Beginning the evening of October 12 thru the day of October 13, 2006 a large snow storm with 25 mph winds deposited 1-2 feet of heavy wet snow on western NY. The utility immediately implemented its contingency alert and public alert plans. This resulted in structure damage due to downed lines of the sub-transmission (20 - 115 kV lines, 1 230 kV line) and distribution systems. Several generation stations were also affected. A total of 90 MW of generation was tripped as a result of a bus trip. Complete restoration of service was achieved by noon October 23.	Y	Y		N	69,198

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10/14/2006 23:25	3.5	PacificCorp	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Bomb Threat	On October 14, 2006 at 11:05 PM, a bomb threat at the coal fired plant was reported to the Security. The telephone message was received from an unidentified caller by a contractor that was installing a new bag house system at the site. The caller stated that the explosive device had been delivered by FEDEx earlier that same day. The local police and the FBI responded to the scene. While the site was searched, plant personnel were evacuated to a nearby parking lot. At 2:57 am October 15, the search for a bomb was completed, it was determined that there was no evidence of an explosive device. Plant personnel and contractors were cleared to re-enter the site. Local police remained on site for the rest of the night. The FBI will follow-up and conduct a trace on the call.	N	N	No FIRM demand interruption reported	Y	
10/15/2006 7:09	19.8	Hawaiian Electric Company	NONE	Y	N	N	UO	291	1,170	Earthquake	On the morning of October 15, 2006, two earthquakes centered off the coast of the Island of Hawaii affected the entire State of Hawaii. The first was a magnitude 6.7 earthquake at approximately 7:07 a.m., and the second was a magnitude 6.0 earthquake at approximately 7:14 a.m. Many aftershocks followed. The earthquakes were felt throughout the island of Oahu and affected their generating facilities. Shortly after the initial and second earthquake, three generating units were lost. Automatic load shedding scheme operated as designed to balance loads with available generation. Subsequent system events resulted in the loss of additional generators until eventually, all the local utilities remaining generating units and those by independent power producers tripped offline to prevent damage to the generators. The restart process was initiated immediately after the earthquake subsided as personnel inspected equipment in the power plants and transmission substations and determined that there was no major damage. The first group of customer loads was picked up by noon while the restoration of the generating units and addition of customer loads continued. The last large area of customers was energized at approximately 2:55 a.m. the following day. Isolated pockets of customers reporting no service or service interruptions were addressed throughout the day on Monday, October 16th.	Y	N	Isolated System	Y	15,495
10/20/2006 13:00	10.0	PECO Energy	RFC	Y	Y	N	UO	92,300	N/A	Weather - Wind Storm and Rain	On October 20, 2006, the utilities service area experienced high winds. Most trouble cases involved fallen trees, downed power lines and damaged electric equipment. By 1 PM, approximately 92,300 customers hadlost service, primarily due to the high winds. An Operating Condition (OpCon) Level 3 was declared due to the number of outages. The Emergency Operations Center (EOC) and all Regional Storm Centers were activated to oversee all response activities. The utilities repair crews along with contract crews worked around the clock from Friday October 20, 2006 to Sunday October 22, 2006. Service outage restoration efforts were completed by 3 PM October 22, 2006 and the system was returned to normal (OpCon level 1).	N	Y		Y	
10/28/2006 9:00	1.0	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	N/A	N/A	Suspicious Surveillance Activities	On the weekend of October 28, 2006, utility work crews observed suspicious activity over the weekend at a substation and storage area.. The crew approached a van but the van left as they approached. The crews found evidence that the site had been enetered and cabinets opened, copper bolts removed, as well as other equipment that were missing. The fence had also been cut and damaged. The local authorities were notified.	N	N	No FIRM demand interruption reported	Y	
10/29/2006 10:53	2.3	New Brunswick System Operator	NPCC-Maritimes	Y	Y	N	UO	N/A	N/A	Human Error - Misoperation	On October 29, 2006, the possible misoperation (at 10:53 am) of a communications tripped three 345 kV and one 115 kV line. Another possible reason for the misoperation may be the fact that the communication line was struck by lightning (7:52 am) earlier that same day. Investigation of the cause of the incident are proceeding.	N	N	No FIRM demand interruption reported	Y	
11/15/2006 13:00	24.0	Puget Sound Energy, Western Washington Puget Sound Region	WECC-RMPA	Y	N	N	UO	50,000	50	Weather - Wind Storm and Rain	By 1 pm on November 15, 2006, a windstorm that began during the morning hours and rincreased during the day caused a distribution disturbance resulting in the loss of service to about 50,000 customers in the affected utilities service area. The high winds continued while the damage assessment and repairs were underway. By noon, November 16, 2006, the weather has stabilized and restoration efforts continued with approximately 17,000 customers without electric service..	Y	Y		Y	804
11/15/2006 15:00	2.0	Southern Company	SERC-Southern	Y	N	N	UO	109,000	363	Weather - Wind Storm and Rain	On November 15, 2006 a major weather front, rain and high winds, moved accross the utilities service area causing wide spread distribution system outages. Restoration and repair activities were enacted by the utility.	Y	Y		Y	486
11/22/2006 7:00	4.0	Sacramento Municipal Utility District	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Sabotage - Copper Theft	On November 22, 2006, at 7 an operator discovered that the copper ground gid connecting straps were cut and stolen from a hydro generating plant. Connecting straps were cut and removed (stolen) at switching platforms, towers, circuit breakers and transformers. The theft was reported to local authorities.	N	N	No FIRM demand interruption reported	Y	

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
11/30/2006 22:00	212.0	Ameren Corp., St Lousi, MO area	SERC	Y	Y	Y	UO	550,000	N/A	Weather - Snow Storm and Ice Storm	On November 30, 2006 the utilities service area was impacted by winds gusting to 25 MPH, a severe ice storm with ice accumulating on power lines and trees nearly 1/2 inch thick, and more than one foot of snow in some areas. The strong winter storm passing through the Midwest has caused power outages. The bulk electric power system is holding up well and no significant problems have occurred or are anticipated. A few transmission lines have tripped due to icing or high winds but they have returned to service. The outages are being caused by damage to the local distribution systems. By December 9th, after nearly nine days of emergency restoration, the utilities Emergency Operations Center closed its doors at 6 PM. Less than 100 customers remain out of service. The work still being done today is largely clean-up and reconnects of customers who, as a result of damage to their own equipment, had to take maintenance outages.	N	Y		N	
12/9/2006 21:56	0.9	PacificCorp	WECC-NWPP	Y	N	N	UO	N/A	N/A	Vandalism - Bomb Threat	On December 9, 2006 , a reported bomb threat at a utilities Control Center was investigated and no bomb was found. The Control Center facilities were not evacuated.	N	N	No FIRM demand interruption reported	Y	
12/13/2006 4:30	317.0	Puget Sound Energy, Western Washington Puget Sound Region	WECC-RMPA	Y	N	N	UO	700,000	N/A	Weather - Wind Storm and Rain	In the morning of December 13, 2006, a major low pressure center moved up the west coast causing a large storm to develop. High winds exceeded 100 mph in some areas. Electrical system disturbances resulted in a loss of greater than 700,000 electrical customers throughout the service area. Extensive damage has occurred over the distribution and sub-transmission systems. December 14 - the high winds continued and the utilities Energy Emergency Operations Center and outlying areas Operating Bases were opened to respond around the clock as needed. December 15 - the major weather event continued with high winds, up to 90 mph. There has been significant damage to Transmission and Distribution infrastructure. Crews continuing around the clock to restore system to normal. December 16 - progress in the restoration of service to the over 320,000 customers who were impacted by the gale-force winds. Approximately 420,000 customers are without electric service. 250 repair crews continue to restore service. 150 additional electric crews are being brought in over the next couple of days. So far, we've re-energized 27 of the 80 transmission lines and 95 of the 150-plus substations that lost power from the storm. December 17 – progress continues, by the end of the night, service will be restored to 500,000 customers. Over 350 crews are working on the restoration efforts, with approximately 50 more arriving over the next two days. There was good progress repairing the transmission system. So far, crews repaired 47 of the 85 transmission lines taken down by the storm, and by re-routing power loads, we've re-energized 129 of the 159 substations that lost power from the storm. By 9:30 am December 26 - all Customers have been restored. All Operating Bases and the	N	Y		N	
12/14/2006 9:44	413.0	Bonneville Power Administration	WECC-RMPA	Y	N	N	UO	15	133	Weather - Wind Storm and Rain	In the morning of December 14, 2006, a major low pressure center moved up the coast causing a large wind storm to develop. This report summarizes outages to customers who were out of service at least 15 minutes in duration. All customers now have electrical service as of 4:44 PM the same day. One of the utilities 230 KV transmission line is out of service and crews are working on this outage. This outage is not impacting electric service to customers. A failure of a 500 KV tower caused an outage to a 500 KV line. A stronger steel lattice tower structure is being fabricated. The line is scheduled to be repaired after December 25th.. This outage has been taken into account and the utility is operating in a reliable manner based on established studies and procdures. During the disturbance, the utility did not exceeded the DOE/NERC 300 MW reporting criteria. A review of the actual outages showed a total to this utility of 133 MW and losses of 233 MW to a neighboring utility to which generation is furnished. It is anticipated that the affected utility will submit their own OE417 report. Reacting to a question from DOE, this utility is volunteerly providing this report.	Y	Y		N	36,802
12/14/2006 12:07	11.9	PacificCorp	WECC-NWPP	Y	N	N	UO	77,500	N/A	Weather - Wind Storm and Rain	On December 14, 2006, a major low pressure center moved up the west coast causing a large storm to develop. High winds exceeded 80 to 100 mph in some areas. Electrical system disturbances resulted in a loss of greater than 50-77,500 electrical customers throughout the service area. Extensive damage has occurred over the distribution and sub-transmission systems. The utility is coordinating its restoration with neighboring utilities.	N	Y		N	

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12/14/2006 17:00	119.0	Tacoma Power - City of Tacoma	WECC-NWPP	Y	N	N	UO	75,000	280	Weather - Wind Storm and Rain	From 5 PM on December 14, 2006 through 1 am December 15, high winds (65 mph gusts) accompanied by heavy rains toppled trees in the service area. Much of the distribution system sustained heavy damage from falling trees and other segments of the sub-transmission system. One 230 KV transmission line was affected with minimal damage. ◻ As of midday, December 15, all Transmission is in normal configuration with everything back in service.◻ As of December 17, 6-8,000 customers are back in service with outages limited to areas with a small number of customers. It may be another 2 to 3 days before all of our remaining affected customers are back in service.	Y	Y		N	22,324
12/14/2006 19:00	36.0	Pacific Gas and Electric Company	WECC-CAMX	Y	Y	N	UO	249,500	N/A	Weather - Wind Storm and Rain	In the morning of December 15, 2006, a major low pressure center moved up the coast causing a large storm to develop. High winds exceeded 100 mph in some areas. Electrical system disturbances resulted in a loss of greater than 250,000 electrical customers throughout the service area. Extensive damage has occurred over the distribution and sub-transmission systems. Extensive damage has occurred over several Oregon counties. Restoration efforts will continue into the weekend to restore all customer loads. The utiliy is coordinating its restoration with neighboring utilities. At 2:30 PM on December 15, a Level III outage was declared. A Level III outage includes multiple substations and feeders out of service, three or four regions experiencing outages and more than 72 hours being required to restore service. Restoration efforts are in full swing with more than 200 crews working on restoration. This storm resulted in a huge number of downed power lines, so addressing those outages and ensuring our customers' safety remains a top priority. Some roads are still impassable due to downed trees and other storm-related damage, making restoration efforts difficult in some areas.	N	Y		N	
12/15/2006 0:01	120.0	Seattle City Light	WECC-RMPA	Y	N	N	UO	170,000	750	Weather - Wind Storm and Rain	On December 15, 2006, a major low pressure center moved up the west coast causing a large storm to develop. High winds exceeded 80 to 100 mph in some areas. Electrical system disturbances resulted in a loss of greater than 170,000 electrical customers throughout the service area. Extensive damage has occurred over the distribution and sub-transmission systems. The utility is coordinating its restoration with neighboring utilities.	Y	Y		N	60,292
12/16/2006 16:30	8.5	Pacific Gas and Electric Company	WECC-CAMX	Y	Y	N	UO	50,000	350	Equipment Failure - Transformer	On December 16, 2006 at 4:30 PM a 320 MVA - 230/115/13kV bulk transformer at a substation caught on fire. The fire continued to burn through the night under the supervision of local fire officials. The transformer had experienced a close-in low side fault during a major storm approximately 36 hours earlier. Manual load shedding was initiated to 7 neighboring 115 kV and 12 neighboring 57 kV substations to clear the 230 kV and 115 kV busses at the affected substation. A total of 89 feeders were removed from service during the event. The load restoration for substation feeders load shed was initiated following isolation of the transformer. All substation feeders opened during the course of this event were restored by 1 am December 17, 2006.	Y	Y		Y	1,989
12/22/2006 15:25	N/A	Electric Reliability Council of Texas (ERCOT) - Tenaska Power Services Co.	ERCOT	Y	Y	N	UO	N/A	3,175	Equipment Failure - Transformer	On December 22, 2006, at 2:59:11 am the main power transformer failed utility Generating Station A.. Prior to that the system was recovering from an interconnection disturbance when a switch tripped resulting in a loss of 202 MW import. Shortly after that, a loud bang was heard at Station A and a transient 10 kV drop in the 345 kV voltage was observed by plant operators. Two substations over at Station B tripped on undervoltage due to this transient voltage disturbance. Moments later, Stations C and D tripped on undervoltage. The Reliability Coordinator Load Acting as A Resource (LAAR) Ancillary Service Market for Responsive Reserve procedures. At 3:09:11am, 1,037 MW of LAAR had been deployed. At 3:03 am, Step 1 of the regions Emergency Electric Curtailment Plan (EECP) was declared, as physical responsive reserve was below its required limit. Total MW lost were 2,138 MW. At 3:48 am the Reliability Coordinator requested restoration of LAARs. At 4:07 am, EECP Step 1 was terminated.	N	Y		Y	
12/26/2006 0:01	271.0	Pacific Gas and Electric Company	WECC-CAMX	Y	Y	N	UO	850,000	420	Weather - Wind Storm and Rain	In the am of December 26, 2006, a strong storm struck the coast and brought heavy rains and strong winds to the coastal areas and significant snowfall and high winds to the mountains, witht lesser rainfall totals and winds to the central valley areas. The coastal areas were particularly hard hit as very strong winds continued long after the precipitation passed through. Approximately 850,000 customers lost power at one time or another, with no more than about 175,000 out at any one time. The storm damaged 29 tsub-ransmission lines including 6 - 115 kV, 1 - 70 kV and 22 - 60 kV substations. Most of the damage resulted when trees were toppled by the high winds. However, two 115kV transmission lines were lost when three double-circuit towers collapsed in high winds. Temporary repairs have been made to one circuit of the double-circuit 115kV line and reconstruction of the three collapsed towers located within an environmentally sensitive area will be completed on January 31, 2007. Mutual Aide from other utilities was not required.	Y	Y		N	76,255

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12/30/2006 22:25	N/A	Nebraska Public Power District	MRO	Y	Y	Y	UO	15,000	500	Weather - Snow Storm and Ice Storm	On December 30, 2006 a storm system moved across the state of Nebraska from west to east with heavy precipitation. As temperatures were near the freezing range, it resulted in a leading edge of rainfall, followed by a band of freezing rain and icing conditions. Ice accumulation on power lines and substations caused extensive damage to the transmission and distribution systems of the affected utility and its wholesale distribution suppliers. At one point, over 35 transmission line circuits, those with voltages from 115-345 kV, out of service due to the storm. Of those, three circuits are 230 kV and five circuits are 345 kV. In addition to the transmission system, telecommunications system was damaged because much of the fiber optics cable is carried in the shield wire on the transmission lines which were damaged. Throughout the storm the utilities Control Center operations personnel, in conjunction with our transmission system planning personnel, ran studies and contingency analyses of the system to ensure that system stability and reliability were maintained. Storm conditions remained throughout most of the day on December 31, hampering efforts to assess the scope of the damage. The initial focus was placed on public safety and clearing major highways and railroads of fallen conductors. As of 5:00 p.m. on January 1, 31 transmission lines are out of service - over 130 miles of 115 & 230 kV lines supported by wood pole structures are on the ground. Most of the 345 kV circuits that are out of service are constructed on steel lattice towers. Several private transmission construction contractors have been engaged to assist with the restoration efforts.	N	Y		Y	
1/13/2007 5:00	163.00	Ameren Corp., St Lousi, MO area, States of Missouri and Illinois	SERC	Y	Y	Y	INT	225000	N/A	Weather - Snow, Freezing Rain	DESCRIPTION: Freezing rain began in the Mid-West the evening of 1/12/07 resulted in power outages well in excess of 100,000 customers and roughly 10,000 customers in two respective states. Restoration efforts began the morning of 1/13. Intermittent freezing rains are expected to continue over the four days. Weather forecast indicate high daily temperatures with freezing temperatures overnight. Ice formations are expected to be significant. In total, there were three waves of freezing rain. The storm center (EOC) closed its doors on 1/19 since less than 1,000 customers were out of service and none of these outages were part of the original icing event. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE #11-Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
1/23/2007 13:46	3.2	British Columbia Transmission Company (BCTC)	WECC-NWPP	N	N	N	INT	100000	1000	Human Error - Substation, Result: Islanding	DESCRIPTION: On 1/23/2007 at 1:46 PM, an operator error at Substation A resulted in the lost 3-500 KV North-South transmission lines separating the utility from the Interconnection.. Also lost were 2,935 MW of generation and the loss of ~1,000 MW of load and causing ~90,000 customers to be out of service. The system frequency decreased to 59.784 Hz from 59.992 Hz. The frequency North of the separated area increased to 62.5 Hz from 59.992 Hz. The frequency in the island West of the affected area increased to 60.47 Hz from 59.992 Hz. Restoration commenced at 3:08 PM. At ~3:20 PM the Reliability Coordinator (RC) reported that the Reserve Sharing system had received a request for 1,275 MW of assistance and provided 1,093 MW due to maximum tie line capability going north at the time. At 6:00 PM, the RC reported that restoration of the 3-500-kV lines occurred at the 3:08 PM time reported above. The initial information of EMS and/or AGC control problems at islanded area were caused by the loss of telemetry from Substation A because it was in the dark and the system was split North and South. No EMS or AGC problems exist at time of restoration. CAUSE/ACTION: Alert Notice THRESHOLD CRITERIA: DOE #4-Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system, and DOE #5-Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	Y	Y		Y	2,166
1/30/2007 6:23	6.37	Independent Electricity Market Operator (IMO)	NPCC-Ontario	N	Y	N	UO	N/A	N/A	Equipment Failure - Capacitor Explosion	DESCRIPTION: On 1/30/2007 at 6:23 am, when switching a 230 kV capacitor, the capacitor failed explosively. The 230 kV bus and circuit were removed from service with normal protection operation. The fault caused instantaneous load loss of approximately 1,700 MW of generation. No load was tripped. The resultant large ACE was reduced to zero by 6:27 am. By 7:20 all coincident load appeared to be back on and normal load pick up was occurring. Digital Fault Recorder operation was reported by adjacent control areas. The extent of damage is not known at this time. THRESHOLD CRITERIA: EOP-004 filed.	N	N	No FIRM demand interruption reported	Y	
2/15/2007 16:54	0.0	Duke Energy - Carolinas BA	SERC-VACAR	Y	N	N	UO	N/A	N/A	System Protection - Relay Misoperation	DESCRIPTION: The sequence of events are being gathered and preliminary indications are that the two 230 kV lines tripped and reclosed causing the frequency disturbance from 59.991 to 59.941 Hz. THRESHOLD CRITERIA: EOP-004 report filed.	N	N	No FIRM demand interruption reported	Y	

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2/16/2007 6:46	3.9	PacifiCorp	WECC-RMPA	Y	N	N	INT	3261	20	System Protection - Relay Misoperation	DESCRIPTION: On 2/16/2007at 6:46 am, on a 230 kV transmission line, an A-phase to ground fault caused by a broken guy wire occurred. The line opened at one end correctly, the other did not. Due to this failure, 410 MW of generation, at several units, were tripped off-line, and all 230 kV and 115 kV lines into the station were tripped by back-up protection. The disturbance caused loss of supply to 3,261 customers. All lines and equipment were restored within 3 hours, except for one 230 kV line which remained out of service pending further breaker and relay tests. Summary report filed. The cause of the failure was the inability of the the relays to detect the fault and open the breakers. The matter is under investigation and the 230 kV line will remain out of service until this is resolved. THRESHOLD CRITERIA- WECC report filed	Y	Y		Y	52
2/24/2007 16:00	164.00	MidAmerican Energy Company; NE quarter of Iowa and Rock Island, IL area	MRO	Y	Y	Y	INT	75000	210	Weather - Ice Storm	DESCRIPTION: In the am of 2/24/2007, freezing rain and high winds in the utilities service territory began causing distribution customer outages. Weather conditions continued to deteriorate throughout the day resulting in increasing levels of damage to the utilities electric transmission and distribution systems. By 4 PM on 2/24, approximately 54,000 customers were without power. The storm continued to cause damage and it is estimated that customer outage count peaked near 75,000 customers at approximately 3 AM on 2/25. Service crews and the Control Center began restoring power immediately and the number of customers without power dropped back down to approximately 50,000 around 6 PM on 2/25. By 11 AM on 2/26, power had been restored to all but approximately 34,500 customers. All available utility personnel, as well as contract crews, are working to restore service. On 2/28 MidA has 1,310 outside assistance personnel working to repair storm damaged areas. The outside assistance personnel consist of 900 contract or surrounding utility crewmen, 260 reassigned MidA crewmen and 150 contract tree crewmen. The total number of customers without power is expected to be 3700 by midnight 2/28. Although there was damage to a number of high voltage (100 kV and above) transmission lines, no reportable System Operating Limits occurred. It is estimated that all customer power outages related to the incident will be restored by midnight 3/3. A preliminary completion date for the damaged sections of 345 kV transmission lines is August of 2007. This line is a jointly owned line that is not operated by subject utility. CAUSE/ACTION: Alert Notice	Y	Y		Y	23,075
2/24/2007 18:00	5.78	Alliant Energy	MRO	Y	Y	Y	INT	140000	400	Weather - Ice Storm	DESCRIPTION: On 2/24/2007 an ice event and blizzard conditions through the utilities service territoty. Ice and galloping conductors caused a very large number of transmission line outages, many of these had extensive damage with conductors down and structure failures. Several 345 kV lines were damaged and over 10 miles of structures were downed. By 7 PM that same day, all transmission sources to a significant city were and under frequency load shedding saved local generation and created an island. Around the service territoty several substations were out of service. CAUSE/ACTION:Alert Notice: THRESHOLD CRITERIA: DOE #4-Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system, DOE #5-Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident, DOE #6-Load shedding of 100 Megawatts or more implemented under emergency operational policy, and DOE #11--Loss of electric service to more than 50,000 customers for 1 hour or more..	Y	Y		Y	1,550
2/28/2007 0:45	68.00	Pacific Gas & Electric, Northern CA	WECC-RMPA	Y	Y	N	INT	671189	110	Weather - Snow and Rain	DISTURBANCE: On 2/22/2007 a major winter storm struck the Northern California coast depositing significant snow levels in the low-elevation and mountanious areas. Along the coastal range to elevation 1,000, snow levels were low, about 1 foot. In the mountain areas, at the 6,000 foot elevation, snow deposits were 5-10 feet. Low elevation areas of the utilities service territory received light to moderate rain. At about 12:45 am on 2/25, distribution outages impacted more than 50,000 customers. However, throughout the storm period more than 671,000 customers were impacted. Several generators operated by the utility were affected as were several cogenerators that provide service to the utility. No high voltage transmission lines were affected. There were 8 - 115 kV lines that were affected and 16 - 60 KV lines. CAUSE/ACTION: Alert Notice: THRESHOLD CRITERIA: DOE #11.-Loss of electric service to more than 50,000 customers for 1 hour or more.	Y	Y		Y	5,012
3/1/2007 9:40	37.3	Entergy	SERC-Entergy	Y	N	N	INT	60408	200	Weather - Storms	DESCRIPTION: On 3/1/2007 at 9:40 PM, 60,408 customers, 200 MW loss of demand, were interrupted due to major storm moving through Mississippi, Alabama, Florida and Georgia. By 3/2 at 11 PM the loss of demand was reduced to 65 MW and approximately 19,557 remained without service. Restoration is continuing with no problems anticipated. CAUSE/ACTION: Weather, Repaired/Restored THRESHOLD CRITERIA: DOE # 11. Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	5,003

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3/1/2007 21:40	25.3	Southern Company□ Parts of Al, Ms,Ga, Fl	SERC-Southern	Y	N	N	INT	60408	N/A	Weather - Tornadoes-Rain	DESCRIPTION: On 3/1/2007 a weather disturbance with tornadoes, rain and high wind moved throught the southeast disrupting the distribution systems. Approximately 60,408 customers were interrupted. Restoration and repairs are underway with most customers restored by 11 PM on 3/2. CAUSE/ACTION:Alert Notice: THRESHOLD CRITERIA: DOE # 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
4/5/2007 9:20	27.83	ISO-New England, Maine, Central Maine Power	NPCC-ISO-NE	Y	Y	N	INT	117142	N/A	Weather - Snow Storm	DESCRIPTION: An April 5, 2007 spring snow storm dumped 1-2 ft of heavy wet snow. This resulted in falling trees taking out multiple distribution and sub-transmission circuits. Customer outages exceeded 50,000 at 9:20 am on 4/5 and peaked at 117,142 customers at 12:34 PM on 4/5. Restoration efforts reduced customer outages to less than 50,000 at 1:10 PM on 4/6 (49,851). Restoration for remaining customers will continue through the weekend. CAUSE/ACTION: Heavy Snow Storm, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
4/5/2007 13:00	N/A	ISO-New England; New Hampshire, PS of NH	NPCC-ISO-NE	Y	Y	N	INT	53000	N/A	Weather - Snow Storm	DESCRIPTION: On April 5, 2007, wide spread snow.wind storm affected the Northeast section of the US. A regionall utility had over 53,000 distribution customers out of service for one hour or more from approximately 9 am to 1 PM on 4/5. Restoration and repair of the distrubution system is proceeding. CAUSE/ACTION: Weather, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
4/12/2007 12:32	59.48	LADWP, City of Los Angeles, California	WECC-CAMX	Y	N	N	DR	158977	200	Weather - Wind	DESCRIPTION: On Thursday April 12, 2007 a weather front moved through utilities service area bringing high winds and rain. The distribution system had 79 5-kV feeders relay to lock-out. The Sub-Transmission System had 14 34.5-kV circuits relay to lock-out. A total of 158,977 customers were without power for a period of time with a maximum of 111,000 customers out simultaneously. Utility crews went to extended shift supplemented by contract crews to hasten restoration. There was no impact to generation or transmission assets. Load Demand Lost: 200 MW; 158,977 total out (111,000 maximum) CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored, Implemented a Warning, Alert, or Contingency Plan THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	7,971
4/14/2007 9:00	2.00	National Grid New England Control Center / REMVEC	NPCC-ISO-NE	Y	Y	N	INT	70000	65	Weather - Wind and Rain	DESCRIPTION: On April 16, 2007 a spring storm with high winds, snow, and rain. High winds associated with a storm system that moved through the area Monday resulted in damage and loss of multiple distribution circuits in the utilities service area. At the height of the storm customer outages ranged from 50,000 – 70,000 for approx. 2 hours. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	Y	Y		Y	87
4/16/2007 8:00	61.0	Duke Energy Carolinas, Piedmont amd Mountains of NC and SC	SERC-VACAR	Y	N	N	INT	125000	N/A	Weather - Wind and Rain	DESCRIPTION: Strong gusty northwest winds developed across the mountains, foothills and piedmont counties as a very strong storm system spins off New England. The strong pressure gradient will result in sustained winds between 20 to 30 MPH with gust to 50 MPH from the foothills eastward across the piedmont counties. In the higher elevations of the NC Mountain counties gust to 60 MPH will occur at times today. Numerous power outages occurred across the Carolinas Service Area as the combination of high winds with leaves on the tress results in broken limbs and some scattered downed trees. Restoration efforts in the hardest hit areas are expected to continue through the end of the week. More than 217,500 customers experienced outages at peak Monday as wind gusts from 40 to 60 MPH swept through the Carolinas. Damage from storm resulted in uprooted trees, broken utility poles and downed power lines. 1,000 MW of Demand; 125,000 at 4/16/2007 8:00:00 AM 1,100 MW of Demand; 217,500 at 4/16/2007 8:00:00 PM CAUSE/ACTION: Major Distribution System Interruption, Weather Related, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for	N	Y		Y	
4/16/2007 10:00	12.00	ISO-New England, New Hampshire	NPCC-ISO-NE	Y	Y	N	INT	81000	N/A	Weather - Wind and Rain	DESCRIPTION: On April 16, 2007 a spring storm with snow, wind and heavy rains causing customer outages of greater than 81,000 by 11:15 AM in the utilities service area. Customer restorations in progress at this time. The estimated time to restore the system is up to 12 hours. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
4/16/2007 10:14	60.07	ISO-New England, Central Maine Power	NPCC-ISO-NE	Y	Y	N	INT	127545	N/A	Weather - Wind and Rain	DESCRIPTION: On April 16, 2007 a spring storm with snow , wind and heavy rains causing customer outages of greater than 50,000 by 10:14 am. All outages at time of report are on the 34 KV sub transmission and distribution system. Peak customer outage of 127,545 at 10:18 PM on 4/16. Customer outages went below 50,000 at 2:35 AM on 4/18. All outages are on the 34 KV sub transmission and distribution system. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
4/16/2007 11:00	8.0	Progress Energy Service Territory in North and South Carolina	SERC-VACAR	Y	N	N	INT	60000	N/A	Weather - Wind and Rain	DESCRIPTION: On April 16, 2007 a spring storm with gusty high winds and rain entered the utilities service territory. The storm was the result of an intense low pressure in the Northeast United States. PE-C is experiencing distribution level outages. As of 11:00 AM there were approximately 60,000 customers without electric service. As of 7:00 PM on 4/16, there were approximately 33,000 customers without electric service in the service territory, with the amount of customers without electric service steadily decreasing. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
4/16/2007 14:00	1.00	Baltimore Gas & Electric	RFC	Y	Y	N	INT	56000	N/A	Weather - Wind and Rain	DESCRIPTION: On April 16, 2007 a spring storm with gusty high winds and rain entered the utilities service territory. The storm was the result of an intense low pressure in the Northeast United States. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	
4/16/2007 14:00	51.00	BGE-Constellation Energy Group, Central Maryland, Baltimore City and surrounding counties	RFC	Y	Y	N	INT	56000	160	Weather - Wind and Rain	DESCRIPTION: Beginning on Sunday, April 15, 2007, and continuing through 4/17, an intense low pressure weather system moved through the utilities service area with heavy rain (over 2 inches) and high winds (gusts in excess of 50 MPH). Wide pread outages and distribution system damage included downed wires, trees and limbs on wires, and blown fuses. Additionally, several distribution substation outages and feeder lockouts were forced out of service. Outages are widespread, over 100 utility and contract constructions crews were needed and about 68 service operators were mobilized for the effort. By 2:30 PM on 4/16, the storm was upgraded to a major storm as outages were created at the rate of over 100 per hour. The decision was made to mobilize external crew resources. However, due to similar outages up and down the eastern seaboard, utilities held their company and contractor crews making exteral rersources difficult to obtain. Tthe storm center was closed at 5 PM on 4/18. April 15-17 - at the peak hour of the storm, approx 56,000 customers were without service. April 17-18 - at the peak hour of the storm, approx 138,000 customers were without service. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored	Y	Y		Y	5,467
4/16/2007 14:04	55.9	Dominion, North, East, & central Va. / parts of N.E.-N.C.	SERC-VACAR	Y	Y	N	DR	242000	90	Weather - Wind and Rain	DESCRIPTION: Scattered distribution outages due to winds and rains from storm covering the east coast. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster, Repaired/Restored THRESHOLD CRITERIA: DOE# 11. Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	3,373
5/5/2007 10:56	N/A	Idaho Area	WECC-RMPA	Y	N	N	UO	N/A	240	Human Error	DESCRIPTION: On May 5, 2007 at 10:56 am, a utility was conducting an Energy Emergency Alert training class when an operator undergoing training actually shed load. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: Shed Firm Load REPORT CRITERIA: OE-417 DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy	N	N	Restoration Time Unknown	Y	
5/10/2007 9:57	3.83	Crockett CoGeneration	WECC-NWPP	Y	Y	N	INT	1	N/A	Equipment Failure	DESCRIPTION: On May 10, 2007 at 9:57 am, the utilities combined cycle was operating normally at 150 MW's, the gas turbine inlet bleed heat valve stopped tracking and combustion temperature alarms were reached.. The CT unloaded, the steam turbine tripped, and the main generator breaker was opened by operator. Plant personnel reset and recalibrated the faulty valve. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 NO Criteria Provided	N	N	No FIRM demand interruption reported	Y	

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5/14/2007 11:15	2.58	Crockette Cogeneration	WECC-NWPP	Y	Y	N	INT	1	N/A	Equipment Failure	DESCRIPTION: On May 14, 2007 at 11:15 am the utilities combined cycle unit was operating normally at 120 MW's, the unit's steam turbine manual emergency stop button initiated a turbine trip. The button was caused by a loose wire in the mounting box. The trip cleared before anyone could examine the switch. The switch was tightened and functionally checked before the unit was restarted. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 NO Criteria Provided	N	N	No FIRM demand interruption reported	Y	
5/15/2007 15:00	40.00	DTE Service Area	RFC	Y	Y	Y	INT	66000	500	Weather - High Wind Gusts and Rain	DESCRIPTION: On May 15, 2007 at 9:39 PM, a severe storm entered the utilities service area. At the storms peak, 59000 customers were interrupted by the high winds and rain. A total of 66000 customers were affected overall. The transmission system was not affected. The distribution system experienced storm damage including wires down, damaged and broken poles. All customers were restored by 7 am on May 17. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	13,400
5/16/2007 18:00	60.00	CT Area	NPCC-ISO-NE	Y	Y	N	INT	67000	N/A	Weather - High Wind Gusts and Rain	DESCRIPTION: On May 16, 2007 at 6 PM a severe storm entered the utilities service area. The transmission system was not affected. The impact occurred in the distribution system. A total of 67000 customers were affected. On May 18 at noon 4431 customers were still out of service due to storm related outages. The estimated time of restoration is 12:00 on May 19. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
5/21/2007 13:48	3.03	Crockette Cogeneration	WECC-NWPP	Y	Y	N	INT	1	N/A	Human Error	DESCRIPTION: On May 21, 2007 at 11:48 PM while the utilities combined cycle unit was operating normally at 140 MW's, an operator lifted the cover on high pressure fitting on the gas turbine lubrication sump.. The gas turbine then tripped on low hydraulic lubricating pressure. The unit tripped due to high exhaust temperature spreads. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	N	N	No FIRM demand interruption reported	Y	
5/23/2007 18:08	2.0	Northwest USA	WECC-NWPP	Y	N	N	UO	N/A	N/A	Equipment Failure	DESCRIPTION: At 6:08 PM on May 23, 2007, the utilities 500/230 kV transformer faulted C-ph internally. The adjoining converter station carrying 2255 MW experienced momentary commutation failures of two converters resulting in proper SPS action. About 0.15 seconds after restoring the converter, one phase of 500 kV PCB closed onto the transformer and the subsequent fault forced off the 500 kV line and converter. This resulted in proper SPS dropping of 2321 MW. The 500/230-kV transformer (and corresponding tie line) remains out of service due to damage to the transformer. The 500 kV PCB has been isolated for correction and the utility is investigating the cause of one phase closing into the transformer. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: No Criteria Provided, Regional Summary Report	N	N	No FIRM demand interruption reported	Y	
6/7/2007 12:47	0.5	BPA Service Area	WECC-NWPP	Y	N	N	UO	N/A	N/A	Human Error	DESCRIPTION: On June 7, 2007 at 12:47 PM, a utilities operator caused, human error, the loss of a 230 kV line. Boundary area generation failed to automatically respond properly and system Operators took action and manually ran back Boundary generation within 7 minutes of line loss. No adverse power system conditions resulted. Scheme temporarily wired to immediately drop generation until Runback scheme is repaired. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: EOP-004, No Criteria Noted	N	N	No FIRM demand interruption reported	Y	

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
6/12/2007 12:42	0.67	Ontario CA Area	NPCC-Ontario	N	Y	N	VR	N/A	N/A	Voltage Reduction - Weather - Hot	DESCRIPTION: On June 12, 2007 at 12:42 PM, the utility was experiencing unusually hot and humid weather with temperatures approximately 4 degrees higher than forecast, resulting in a primary demand approximately 1200 MW higher. An EEA 1 had been declared and 200 MW Emergency energy was being purchased to maintain reserve margins. A TLR 3A was in effect due to congestion. At 12:42 PM a 500 KV circuit was automatically removed from service resulting in 744 MW of generation being rejected. Included in the 800 MW operating reserve activation was 5 % voltage reductions. Approximately 500 MW of load relief was realized from the voltage reduction. ACE was reduced to 0 MW by 12:51 am. Frequency prior to the event was on schedule at 60.00 Hz during the event frequency dropped to approximately 59.95 Hz and recovered to 60.00 Hz by12:46 PM. The 500 kV circuit was returned to service at 1:11 PM and the 5% voltage reductions ended at 1:22 PM. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: N/A ACTIONS TAKEN: Reduced Voltage REPORT CRITERIA: OE-417 DOE #7 – System-wide voltage reductions of 3 percent or more	N	N	Voltage reduction	Y	
6/26/2007 15:42	0.80	NY State	NPCC-NYISO	Y	Y	N	UO	N/A	460	Weather – Lightening Strike	DESCRIPTION: On June 27, 2007 at 3:42 PM, the RC confirmed that a lightning strike near the utilities 138 kV substation resulted in the uncontrolled loss of load which was restored by 4:30 PM the same day. The lightning strike momentarily affected communication equipment that prompted circuit breakers on multiple transmission feeders to open, causing the service interruption. All other electric system components operated properly to contain the event from spreading and protected equipment needed for service restoration. There were no reliability impacts outside the local area. TYPE OF EMERGENCY: Major Transmission System Interruption; Major Distribution System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster – Lightening Strike ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	Y	Y		Y	247
6/27/2007 15:54	49.3	BC Province	WECC-NWPP	N	N	N	UO	N/A	140	Weather - Lightening Suspected	DESCRIPTION: On June 27, 2007 at 3:54 PM, the utilities 500 kV line faulted (lighting suspected) causing the tripping and re-close of this circuit. Two 500/230 kV transformers tripped coincident with the line fault. Tripping of the transformer zone also resulted in opening of another 500 kV line. The loss also resulted in the interruption of a 230 kV supply to two substations. At 3:56 PM, approximately 140 MW of load was interrupted at due to currently unknown cause that may be related to the initial loss of the substation outages. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: Regional Report Summary, NO Criteria Noted	Y	Y		Y	4,620
6/28/2007 17:18	72.7	Northwest USA	WECC-NWPP	Y	N	N	UO	N/A	N/A	Equipment Failure - NON-Transmission System	DESCRIPTION: On June 28, 2007, at 5:18 PM, the generation utility while shifting oil filters on a Condensate Booster Pump, a motor tripped due to low oil pressure followed by a trip of both Reactor Feed Turbines on low suction pressure. The reactor was manually scrammed, resulting in loss of 800 MWe of generation. No equipment damage occurred, No critical infrastructures were interrupted, and no other electrical systems were affected. Resolution: Changed operating procedures to remove Condensate Booster Pumps from service before shifting oil filters. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	N	N	No FIRM demand interruption reported	Y	

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
6/29/2007 9:23	0.8	Phoenix Area	WECC-AZNMSNV	Y	N	N	INT	98700	399	Equipment Failure - EMS Load Shedding Tool	DESCRIPTION: On June 29, 2007 at 9:23:14 am, the utility experienced an uncontrolled loss of 399 MW of firm load due to a malfunction of the Energy Management System computer load shedding tool. At the beginning of the event the system frequency was 59.997 Hz and peaked at 60.031 Hz at 9:23:34 am. By 10:09 am all firm customer load lost was restored. The EMS load shed tool has been temporarily disabled pending investigation and testing. The backup load shedding process is still available. There was no impact to the transmission system due to this event. There was no loss of generation. There was no sabotage associated with this incident. The event was triggered by the status change of several dynamic transfer signals to telemetry error which biased the calculated load higher than the target load set in the load shed application. The load shed application began opening distribution circuits. Since the event, the biasing of calculated load due to telemetry errors has been removed. The feature that causes the load shed application to operate in automatic mode will be disabled prior to making it available again to operation. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Other REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	Y	Y		Y	205
7/3/2007 10:59	7.02	CAISO Controlled Grid	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Public Appeal - Weather	DESCRIPTION: On July 3, 2007 at 7:10 am, due to high temperatures and loss of transmission capacity and generation in the area, the RC has made a public appeal as of 11:00 am for increased conservation for the period between 2 and 6 PM, as well as through the week. On July 5, the RC continued conservation for the period between 2 and 6 PM due to continuing high temperatures and demand. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
7/6/2007 17:18	1.0	Southern Idaho, Easter Oregon	WECC-NWPP	Y	N	N	UO	N/A	60	Weather – Storm and Fires	DESCRIPTION: On July 6, 2007 at 5:18 PM severe storm entered the utilities service area with lightning and winds of 40mph and gusts of over 50mph. Between 3:20 and 4:51 PM the utility had several transmission lines trip and close. During this time there were reports of fire in the area and high winds. At 4:58 PM, a substation plus two 230 kV, three 345 kV, and one 500 kV associated transmission lines failed. By 5:12 PM fire had taken one more 345 kV line out of service. By 6:20 PM, operators were able to restore our reserves to required levels and returned to an EEA-0 at 6:20 PM. The damaged substation structures were repaired and returned to service by midnight July 7L As of July 8 at 8 am there are still two 345 kV lines out of service one with 14 transmission structures damaged. One line is expected to return to service July 9 and the other by the middle of the week. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: Transmission Equipment; Loss of Part or All of a High Voltage Substation or Switchyard; Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	Y	Y		Y	42
7/7/2007 19:00	12.00	Southeastern MI	RFC	Y	Y	Y	INT	69000	N/A	Weather – Storm	DESCRIPTION: On July 5, 2007 at 7 PM a severe storm entered the utilities service area affecting the distribution system. The storm continued through 7 am on July 8. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
7/10/2007 11:00	43.00	Eastern NY	NPCC-NYISO	Y	Y	N	INT	300000	650	Weather – Firm Load Shed	DESCRIPTION: On July 10, 2007 at 11 am, a storm entered the utilities service area. The storm damaged the 34.5 kV distribution system causing the shedding of 75 MWs of load. Later in the evening another storm developed tripping two115 kV lines at 7:09 PM. This resulted in the loss of approximately 250 MW of generation. At 7:21 PM six 115 kV lines tripped resulting in low voltages below load shed limits. Operators initiated manual load shedding. Approximately 650 MWs of load was lost due to storm damage and load shedding. Of that approximately 100 MW of load was shed. All lines, generation and customers have been restored. These events did not impact the Bulk Power System. TYPE OF EMERGENCY: Major Transmission System Interruption; Major Distribution System CAUSE OF INCIDENT: Inadequate Electric Resources to Serve Load; Weather or Natural Disaster ACTIONS TAKEN: Shed Firm Load; Repaired/Restored REPORT CRITERIA: OE-417 DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	18,726

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7/15/2007 19:28	N/A	Western portion of TVA service area	SERC-TVA	Y	N	N	UO	N/A	N/A	Equipment Failure	DESCRIPTION: NOTE: This event did not meet the DOE OE-417 or NERC EOP-004 trigger criteria but was provided as a courtesy since it approaches the reporting limits. On July 15, 2007 at 7:28 PM the utility experienced a voltage dip emanating from the western area of the system. The utilities loads dropped and frequency rose to 60.06 Hz. The utilities equipment responded appropriately and action were taken to reduce generation to balance the system and restore ACE in about 6 minutes of the initial system disturbance. It was determined that a 161 kV/ 23 kV transformer bank in western substation had failed due to a lightning arrestor failure and recording devices showed a 3 phase fault which cleared as designed. TYPE OF EMERGENCY: Other – Disturbance of Distribution System CAUSE OF INCIDENT: Transmission Equipment ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	N	N	No FIRM demand interruption reported	Y	
7/16/2007 16:17	3.0	Utah Area	WECC-NWPP	Y	N	N	UO	N/A	306	Natural Disaster – Fires	DESCRIPTION: On July 16 at 4:17 PM, the utility reported that three 138 kV lines relayed to lock out. All three lines run in the same corridor and a fire was reported under the lines. At least one structure is down.. Fire crews would not allow line crews in the area to inspect during the event. Air patrol attempted to get a visual of the damage. At 7:18 PM two of the 138 kV lines were restored to service and customer load restoration commenced. Station Service problems hindered the restoration process. All customers were reported back in service at 8 PM, and the system is stable. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Natural Disaster – Fires ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	Y	Y		Y	618
7/17/2007 18:00	8.00	EXELON Corp West ComEd	RFC	Y	Y	N	INT	90000	300	Weather - Thunderstorms and High Wind	DESCRIPTION: Severe storms moved through the service area. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster. THRESHOLD CRITERIA: DOE# 11.Loss of electric service to more than 50,000 customers for 1 hour or more.	Y	Y		Y	1,608
7/19/2007 15:00	80.50	Southwestern Region of DTE Service Territory	RFC	Y	Y	Y	INT	60000	N/A	Weather - Thunderstorms and High Wind	DESCRIPTION: On 7/19/2007 at 3 PM, a storm entered the service area. About 60,000 distribution customers were out od service. By 11 PM that evening, less than 50,000 customers were without service and by 10am 7/20 it was approximately 24,000. customers still remained out of service. The service territory experienced heavy tree damage resulting in numerous broken poles and wire down mostly concentrated in our south west region. As of 11:30 PM on 7/22 all service has been restored to all the customers affected by this storm. CAUSE/ACTION: Major Distribution System Interruption, Weather or Natural Disaster THRESHOLD CRITERIA: DOE# 11.Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
7/19/2007 15:50	6.4	Dominion–Virginia Power/North Carolina Power	SERC-VACAR	Y	Y	N	INT	107000	72	Weather - Thunderstorms and High Wind	DESCRIPTION: 7/19 Scattered distribution outages due to thunderstorms and high winds from storms covering the east coast from Norfolk through central and northern Virginia. The result was scattered distribution outages affecting 107,000 out at the peak. Service was substantially restored to the majority of customers by 10:00 PM. Normal storm restoration procedures were put into effect CAUSE/ACTION:Major Distribution System Interruption, Weather or Natural Disaster THRESHOLD CRITERIA: DOE# 11.Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	310
7/31/2007	N/A	N/A	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Equipment Failure	DESCRIPTION: On July 31, 2007 the GO/GOP experienced an outage of one of two generating units (221.5 MW) generator. The Go/GOP is NOT an LSE and does not serve "end users." NOTE – Report NOT Required TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: EOP-004, Attachment 1, Item 4.b. ...Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below: ...Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW. DOE #1 – Actual physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations	N	N	No FIRM demand interruption reported	Y	
8/4/2007 5:43	12.02	RFC West to MISO East	RFC	Y	Y	N	UO	N/A	N/A	Equipment Failure	DESCRIPTION: On August 4, 2007 at 5:43 PM, a 765kv line tripped and locked out causing the loss of 4,262 MW of generation in the three utilities. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: EOP-004 No Criteria Provided	N	N	No FIRM demand interruption reported	Y	

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8/8/2007 13:00	8.0	Portions of NC and SC	SERC-VACAR	Y	N	N	PA	N/A	N/A	Public Appeal - Weather - Hot	DESCRIPTION: On August 8, 2007 at 1 PM EST, in coordination with the State Governor's Office's appeal to the public to reduce electricity demand, the utility issued a general customer appeal to reduce demand due to extreme heat. Temperatures across the service territory had reached 100 degrees or more by noon. The utility has also issued an order to company employees to curtail non-essential load at utility owned facilities. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
8/8/2007 15:56	4.07	Mid-Atlantic Region of PJM	RFC	Y	Y	N	VR	N/A	N/A	Voltage Reduction	DESCRIPTION: On August 8, 2007 at 3:56 PM EST, the RC implemented a 5% voltage reduction in an area, due to inadequate resources to serve firm demand. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Inadequate Electric Resources to Serve Load ACTIONS TAKEN: Reduced Voltage – 5%; Implemented a Warning, Alert, or Contingency Plan REPORT CRITERIA: OE-417 DOE #7 – System-wide voltage reductions of 3 percent or more DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Voltage reduction	Y	
8/9/2007 12:45	8.3	Portions of NC and SC	SERC-VACAR	Y	N	N	PA	N/A	N/A	Public Appeal - Weather - Hot	DESCRIPTION: On August 9, 2007 at 12:45 PM EST, the utility issued a general customer appeal to conserve energy to reduce demand due to extreme heat. Temperatures across the service territory had reached 100 degrees or more by noon. The utility also issued an order to company employees to curtail non-essential load at utility owned facilities. This appeal is for customers to reduce for conservation purposes only and is not linked to an emergency capacity deficiency. The customer appeal ended at 11 PM. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
8/10/2007 12:20	8.7	Portions of NC and SC	SERC-VACAR	Y	N	N	PA	N/A	N/A	Public Appeal - Weather - Hot	DESCRIPTION: On August 10, 2007 at 12:20 PM the utility issued a general customer appeal to conserve energy to reduce demand for Friday, August 10 due to extreme heat. Temperatures across the service territory had reached 100 degrees or more by noon. The utility also issued an order to company employees to curtail non-essential load at the utilities facilities. This appeal is for customers to reduce energy consumption for conservation purposes only and is not linked to an emergency capacity deficiency. The customer appeal ended at 9 PM. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
8/13/2007 1:30	34.50	State of MO	SERC	Y	Y	Y	INT	63000	N/A	Weather - Severe Storm - High Winds	DESCRIPTION: On August 13, 2007 at 1:30 am, a severe thunderstorm entered the utilities service area. The incident impacted the distribution system but NOT the transmission system. The storms high winds and lightning resulted in outages to approx 63,000 customers. Utility crews and contractors responded to the damage to restore customers. More than 95% of the customers were restored within 24 hours. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
8/13/2007 18:11	2.82	Shasta, CA	WECC-CAMX	Y	Y	N	UO	N/A	N/A	Human Error	DESCRIPTION: On August 13 at 6:11 PM, an operator erroneously closed a ground switch on a generating unit while it was on-line, causing it and three other units at the station to trip (408 MW) and bypass the 230 kV bus differential protections. This caused a fire and damaged the ground switch and possibly damaged one of the generating units. A project is underway to reconfigure the 230 kV bus to double bus and double breaker scheme in the coming year. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: NERC EOP-004 filed	N	N	No FIRM demand interruption reported	Y	

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
8/14/2007 14:00	4.00	CSWS area of SPP	ERCOT	Y	Y	N	INT	5	N/A	Weather - Shed Interruptible Load	DESCRIPTION: On August 14, 2007 at 2 PM, the utility implemented Step 6 of its emergency operation plan due to high temperatures and generating unit unavailability. Non-firm sales have been recalled and interruptible customers will be curtailed from 2-6 PM. A NERC EEA2 was declared at 1 PM. TYPE OF EMERGENCY: Major Generation Inadequacy CAUSE OF INCIDENT: N/A ACTIONS TAKEN: Shed Interruptible Load REPORT CRITERIA: OE-417 DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy	N	N	No FIRM demand interruption reported	Y	
8/18/2007 4:08	0.2	Arizona PS	WECC-AZNMSNV	Y	N	N	UO	N/A	N/A	Equipment Failure - Relay Setting	DESCRIPTION: On August 18, 2007 at 4:08 am, in the utilities transmission system several lines opened and a 500 kV line tripped causing N to S overloads. A city within the control area experienced a voltage deviation and recovered within several minutes. Series capacitor banks tripped, further curtailing E-W transfers. There was residual damage to capacitor banks at on a 500 kV line and another line. The 500 kV capacitor bank was returned to service that same day and the other scheduled for repairs the week of August 20. No generators were tripped because of this disturbance. The cause of the line trip is believed to be relay miss-coordination based on information obtained from downloading data from the relay. The utility has made relay setting changes as appropriate. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: WECC Region Summary Report, NO CAUSE STATED	N	N	No FIRM demand interruption reported	Y	
8/19/2007 23:34	1.60	Central and Eastern VA	SERC-VACAR	Y	Y	N	INT	58500	100	Weather - Storm - Rain - High Wind Gusts	DESCRIPTION: On August 19, 2007 at 11:34 PM, thunder storms entered the utilities central and eastern service territories affecting 50,000 – 58,500 customers. The storm impacted the distribution system. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	107
8/23/2007 16:00	20.00	Commonwealth Edison Area	RFC	Y	Y	N	INT	300000	N/A	Weather - Storm - Rain - High Wind Gusts	DESCRIPTION: On August 23, 2007 at 4 PM, thunder storms entered the utilities central and eastern service territories affected approx 300000 customers. The storm impacted the distribution system. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
8/24/2007 20:27	0.9	Alberta Province Area	WECC-NWPP	Y	N	N	UO	N/A	N/A	Animal Contact	DESCRIPTION: On August 24, 2007 at 8:27 PM an AC/DC/AC converter tripped at 153 MW and overpower scheme operated as designed to trip a 138 kV lines islanding the utility from the interconnection. At 9:20 PM the converter was back in service and the cause of trip was an animal intrusion at the facility. The frequency at the islanded utility deviated from 60.013 to a low value of 59.774 Hz and returned to 60 Hz at 8:31 PM. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: WECC Region Summary Report	N	N	No FIRM demand interruption reported	Y	
8/25/2007 10:58	N/A	Generation Station	SERC-VACAR	Y	N	N	UO	N/A	N/A	Equipment Failure - Relay	DESCRIPTION: On August 25, 2007 at 10:58:47 am, the utility experienced a fault in a step-up transformer bank at a generation station. The fault caused seven generating units and five transmission lines to trip. The relay operations are being investigated. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: NERC EOP-004 Report	N	N	No FIRM demand interruption reported	Y	
8/25/2007 18:00	60.50	Southeastern MI	RFC	Y	Y	Y	INT	75000	N/A	Weather - Storm - Rain - High Wind Gusts	DESCRIPTION: On August 25, 2007 at 6 PM, a severe rain storm entered the utilities service area impacting the distribution system. Approx 75000 customers were affected. At 6:30 am on August 28 service had been restored to all of the customers. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored Report Criteria: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
8/29/2007 13:53	1.07	City of Modesto	WECC-CAMX	Y	N	N	INT	26000	180	Animal Contact VEGETATION	DESCRIPTION: On August 29, 2007 at 1:53 PM, the utility reported that a 230 kV transmission line locked out as a result of vegetation contact. This was followed by a 230 kV line breakers opening. This N-2 condition activated a scheme to protect the 115 kV transformers from overloading and shed 84 MWs. Due to high temperatures the load continued to grow and the dispatchers had to load shed an additional 96 MWs between 2:18 and 2:39 PM. The affected circuit was trimmed on August 30. CAUSE OF INCIDENT: Other ACTIONS TAKEN: Shed Firm Load; Repaired/Restored REPORT CRITERIA: OE-417 DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy	Y	Y		Y	129
8/28/2007 16:00	26.00	Southern California	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Public Appeal - Weather- Hot	DESCRIPTION: On August 28, 2007 a late-summer heat wave is bearing down on CA and the western region this week and the CAISO expects to see the highest electricity demands of the summer. The CAISO declared Wednesday and Thursday "Flex Alert Days" and urged CA California consumers to conserve energy and reduce demand on the system during the peak hours of 4 to 6 PM On August 29, 2007 at 3 PM, CAISO declared a Warning effective 3-8 PM due to high temperatures causing high loads and lack of import capability. At 1:20 PM a CAISO Stage 1 Electrical Emergency was declared, effective 3:20-8 PM. On August 30, 2007 the CAISO declared a Warning effective 2-8 PM due to high loads with limited resources. CAISO declared a "Flex Alert" for August 31 and asked electric customers to continued conservation efforts. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Weather ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
8/31/2007 12:45	7.25	CAISO Area	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Public Appeal - Weather- Hot	DESCRIPTION: On August 31, 2007 at 12:45 PM, the utility declared a Warning, effective through 8 PM, due to high loads. The RC also requested available assistance from neighboring BA's. The Warning was cancelled at 5 PM. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Weather ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
9/3/2007 12:30	5.00	San Diego Area	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Weather – High Temperatures & Humidity	DESCRIPTION: On Sept 3, 2007 at 12:30 PM, the utility experienced extreme weather conditions of high temperature and humidity resulting in extremely high system loads. Given the load ramp rate, earlier in the day utility made a public appeal. Since that appeal, the load ramp rate lessened due to public response and somewhat cooler temperatures. As a result, the issue that prompted the utilities concerns has been resolved. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Weather or Natural Disaster – High Temperatures & Humidity ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
9/4/2007 8:30	7.00	San Diego Area	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Weather – High Temperatures & Humidity	DESCRIPTION: On Sept 4, 2007 at 8:30 am, the utility experienced a continuation of the extreme weather conditions, high temperature and humidity, resulting in extremely high system loads, 500 MW over the previous day. Given the load ramp rate, the utility made a public appeal. Since that appeal, the load ramp rate lessened due to public response. This was a distribution event. There was no involvement from RC or Region. The transmission system worked well this weekend and there were ample generation assets. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Weather or Natural Disaster – High Temperatures & Humidity ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	

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Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
9/5/2007 7:53	5.30	Central Texas	ERCOT	Y	Y	N	UO	N/A	N/A	Equipment Failure-Relay	DESCRIPTION: On Sept 5, 2007 at 7:52 am, two generating unit station was on line and running at 1,084 MW net with no abnormal conditions or indications present. At 7:53 am, in response to a close in fault on the dual circuit 345 KV transmission lines, both units tripped. The lines were faulted and forced out due to severe weather (tornado) conditions. The system frequency was 60.01 Hz prior to the disturbance and dropped to 59.74 Hz. At 8:00 am, system frequency had risen to 60.14 Hz. The first fault was an A phase to ground fault on Line A. The second A-phase to ground fault occurred 0.57 seconds later on Line B. The third fault occured 0.20 seconds later 3-phase fault to ground on Line A. Line A protective relaying correctly operated, locked out, and isolated the 3-phase permanent fault in approximately 3 cycles. The fourth fault occurred 0.5 seconds later was a 3-phase fault to ground on Line B. Line B protective relaying operated correctly, locked out, and isolated the 3-phase permanent fault in approximately 3 cycles. The control system functioned as designed, and as intended. The control system tripped the units before damage could occur, and the units were restarted and returned to service the same day. TYPE OF EMERGENCY: Other, generation lost due to severe weather CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Other REPORT CRITERIA: EOP-004 and OE-417, NO criteria listed	N	N	No FIRM demand interruption reported	Y	
9/13/2007 4:00	27.00	State of LA Area	SPP	Y	Y	N	INT	118000	N/A	Weather – Hurricane Humberto	DESCRIPTION: On Sep. 13, 2007 at 1:45 am, the utility reported that hurricane Humberto made landfall as a strong Category 1 hurricane with max winds of 85 mph. By 4 am electric service to more than 50,000 customers for 1 hour or more was exceeded. At peak, 118,000 customers were affected. As of 4 PM on Sep. 14, restoration continues for 59,000 customers, with restoration for some customers expected to be as long as 5 days. As of Sep. 14, noon, 37 of 55 affected transmission lines have been restored and 53 of 66 affected substations have been restored. Tropical depression Humberto system exited the utilities service territory around 7 am Sep. 14. TYPE OF EMERGENCY: Major Transmission System Interruption; Major Distribution System CAUSE OF INCIDENT: Weather or Natural Disaster – Hurricane Humberto ACTIONS TAKEN: Implemented a Warning, Alert, or Contingency Plan; Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
9/15/2007 18:17	0.33	Hydro-Quebec Transenergie	NPCC-HQ	N	Y	N	UO	N/A	N/A	Equipment Failure - Fire	DESCRIPTION: On Sept 15, 2007 at 6:17 PM the utility reported that a potential transformer fire on a substation bus resulted in the tripping of several lines. The utility lost 1371 MW of incoming energy, 120 MW of generation from Station A, plus 750 MW of industrial load due to frequency deviation. All generation service was restored by Sept 16. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Transmission Equipment ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: Modified OE-417, NO Criteria Identified	N	N	Restoration Time Unknown	Y	
9/17/2007 19:01	0.78	Crawfordsville, IN	RFC	Y	Y	Y	INT	9600	50	Equipment Failure - Relay	DESCRIPTION: On Sept 17, 2007 at 7:01 PM, a radial utility fed by another utility through a 138 kV substation experienced separation due to the tripping of a breaker. This left the city served by the radial utility without power. It was later determined that a relay had cause the breaker to trip. TYPE OF EMERGENCY: Major Transmission System Interruption ; Major Distribution System CAUSE OF INCIDENT: Electrical System Separation – Islanding ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #3 – Complete operational failure or shut-down of the transmission and/or distribution electrical system	Y	Y		Y	26
9/18/2007 5:20	0.17	MN, ND, MB - NSP	MRO	Y	Y	Y	INT	6000	4700	Electrical System Separation – Islanding	DESCRIPTION: SEE NERC PRESS RELEASE - Violent wind storms moving through the Dakotas and Minnesota forced 20 transmission lines (mainly 345 kV) out of service. At about 6:20 am EDT, a large portion of the western Midwest Independent System Operator (MISO) lost power. MISO was able to restore the U.S. section of the grid within 10 minutes, and will remain in conservative operation until 6:20 pm EDT. Saskatchewan Power also separated from the Eastern Interconnection when it lost its 230 kV tie lines into Manitoba and North Dakota. Generation outages totaling 896 MW occurred as well, resulting in customer outages. Saskatchewan Power reconnected to grid within an hour. Almost all customer load was restored within 2 hours. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Electrical System Separation – Islanding; Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #4 – Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system	Y	Y		Y	525

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
9/18/2007 5:15	1.25	MN, ND, MA - Great Rivers	MRO	Y	Y	Y	INT	11175	8,000	Electrical System Separation – Islanding	DESCRIPTION: SEE NERC PRESS RELEASE - Violent wind storms moving through the Dakotas and Minnesota forced 20 transmission lines (mainly 345 kV) out of service. At about 6:20 am EDT, a large portion of the western Midwest Independent System Operator (MISO) lost power. MISO was able to restore the U.S. section of the grid within 10 minutes, and will remain in conservative operation until 6:20 pm EDT. Saskatchewan Power also separated from the Eastern Interconnection when it lost its 230 kV tie lines into Manitoba and North Dakota. Generation outages totaling 896 MW occurred as well, resulting in customer outages. Saskatchewan Power reconnected to grid within an hour. Almost all customer load was restored within 2 hours. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Electrical System Separation – Islanding; Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #4 – Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system	Y	Y		Y	6,700
9/18/2007 5:15	0.92	MN, ND, MB - MISO	MRO	Y	Y	Y	INT	n/a	N/A	Electrical System Separation – Islanding	DESCRIPTION: SEE NERC PRESS RELEASE - Violent wind storms moving through the Dakotas and Minnesota forced 20 transmission lines (mainly 345 kV) out of service. At about 6:20 am EDT, a large portion of the western Midwest Independent System Operator (MISO) lost power. MISO was able to restore the U.S. section of the grid within 10 minutes, and will remain in conservative operation until 6:20 pm EDT. Saskatchewan Power also separated from the Eastern Interconnection when it lost its 230 kV tie lines into Manitoba and North Dakota. Generation outages totaling 896 MW occurred as well, resulting in customer outages. Saskatchewan Power reconnected to grid within an hour. Almost all customer load was restored within 2 hours. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Electrical System Separation – Islanding; Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #4 – Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system	N	N	No FIRM demand interruption reported	Y	
9/18/2007 5:21	0.82	MN, ND, MB - SASK Power	MRO	Y	Y	Y	INT	n/a	896	Electrical System Separation – Islanding	DESCRIPTION: SEE NERC PRESS RELEASE - Violent wind storms moving through the Dakotas and Minnesota forced 20 transmission lines (mainly 345 kV) out of service. At about 6:20 am EDT, a large portion of the western Midwest Independent System Operator (MISO) lost power. MISO was able to restore the U.S. section of the grid within 10 minutes, and will remain in conservative operation until 6:20 pm EDT. Saskatchewan Power also separated from the Eastern Interconnection when it lost its 230 kV tie lines into Manitoba and North Dakota. Generation outages totaling 896 MW occurred as well, resulting in customer outages. Saskatchewan Power reconnected to grid within an hour. Almost all customer load was restored within 2 hours. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Electrical System Separation – Islanding; Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #4 – Electrical System Separation (Islanding) where part or parts of a power grid remain(s) operational in an otherwise blacked out area or within the partial failure of an integrated electrical system	Y	Y		Y	490
9/24/2007 13:38	3.37	Southwest Michigan	RFC	Y	Y	Y	UO	N/A	N/A	Equipment Failure – Condensate Vacuum	DESCRIPTION: On Sept 24, 2007 at 1:38 PM, Generation Operator generating unit #3 tripped due to the loss of condenser vacuum resulting in the loss of 320 MW. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Other REPORT CRITERIA: OE-417 DOE #5 – Uncontrolled loss of 300 Megawatts or more of firm system loads for more than 15 minutes from a single incident	N	N	No FIRM demand interruption reported	Y	
10/3/2007 16:35	0.65	Quebec Area	NPCC-HQ	N	Y	N	UO	N/A	N/A	Human Error - Line Load Limit Exceeded	DESCRIPTION: The utility reported a violation of a transmission limit for more than thirty minutes. On Oct 3, 2007 at 4:35 PM, a 735 kV line on a radial transmission corridor tripped while another line in same corridor was out of service for maintenance. A human error caused the initial line trip. It is still under investigation. The transmission capacity dropped and the dispatchers rapidly began to re-dispatch the generation in the corridor. Some deliveries were cut. On the corridor, the flow decreased below the post-contingency normal limit for 31 min. 55 sec. after the tripping of the line. The emergency limit was not available at that time for that unusual configuration. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: DOE OE-20 Emergency Report	N	N	No FIRM demand interruption reported	Y	

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Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
10/7/2007 12:35	4.42	Portola, CA	WECC-CAMX	Y	Y	N	INT	2500	10	Distribution Transformer Failure - Squirrel	DESCRIPTION: On Oct 7, 2007 at 12:35 PM, a squirrel caused a fault on the 12 kV distribution side of a substation transformer operated by the utility. A 60 kV breaker opened to clear the fault. The outage was contained within the utilities system. The utility was operating at 17 MW, from a peak of 27 MW, the system dropped to 6 MW. The utility is investigating equipment operation and configuration to determine appropriate follow-up actions. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: EOP-004	Y	Y		Y	30
10/10/2007 14:28	2.53	Portola, CA	WECC-CAMX	Y	Y	N	INT	7500	15	Weather - High Wind Gusts	DESCRIPTION: On Oct 10, 2007 at 2:28 am, high wind gusts caused transmission lines to come together causing the utilities substation to open, separating the utility from the neighboring utility. Approx 7500 customers were affected and 15 MW of firm energy lost. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: NERC EOP-004	Y	Y		Y	25
10/15/2007 3:14	1.6	PACE Area	WECC-RMPA	Y	N	N	UO	N/A	N/A	Off-Normal Operation – Specific Cause Being Investigated	DESCRIPTION: On Oct 15, 2007 at 3:14 am, the utilities X-Y 345 kV line tripped. Relaying responded correctly opening the line due to a single-line-ground fault caused by an A-phase conductor being down. The X-W1 138-kV line tripped at approx the same time. At 3:20 am the Reliability Coordinator curtailed interruptible loads to reduce loading on remaining 138 kV lines. At 3:21 am the RC requested immediate reduction of generation. At 3:27 am the X-W2 138kV line tripped. Approx 1 minute later, the remaining X-W3 138 kV line tripped. Additional generation was curtailed to reduce loading within limits. All 138 kV lines were restored by 4:52 am and interruptible loads were restored by 5:19 am. The X-Y 345 kV line remains out-of-service to repair the conductor. Cause of the 138 kV line trips are under investigation. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: WECC Summary Report	N	N	No FIRM demand interruption reported	Y	
10/18/2007 15:00	21.0	Western WA Area	WECC-NWPP	Y	N	N	INT	160000	N/A	Weather - High Wind Gusts	DESCRIPTION: On Oct 18, 2007 at 3 PM, a significant weather event occurred in the utilities service area affecting over 165000 distribution customers. High winds, up to 50+ mph, resulted in damage to Transmission and Distribution infrastructure. The utilities Emergency Operations Center and all outlying areas Operating Bases were opened. Crews are working around the clock to restore system to normal. Current estimate is two to three days for complete restoration. On Oct 19, seven transmission lines were off but the utility restored supplies to all substations due to multiply supplies into the substations. No customers were without service due to the transmission outages. They have restored service to 152,000 customers and have 14,000 remaining to restore. Utility crews have encountered an extensive amount of damage to the utility's power system from wind-blown trees and limbs. TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: N/A REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
10/22/2007 14:01	0.35	SCE – LA Area of CA	WECC-CAMX	Y	Y	N	INT	90323	451	Fires - Brush Fires	DESCRIPTION: On Oct 22, 2007 at 2:01 PM, the utility reported a 220 kV lines relayed when brush fire burned under both lines. At 2:05 PM manual load shedding was initiated (551 MW) and a 220 kV line exceeding its 15 minute emergency loading limit as result of the relay operations. Approximately 90,323 customers were affected. At approx 2:06 PM 200 MW of firm load was requested. At 2:08 PM the Reliability Coordinator declared a regional transmission emergency. By 2:20 PM both 220 kV line were returned to service and by 2:43 all customers were restored. The fires continue to burn in through Oct 23. A substation was taken off line and numerous distribution lines were de-energized. The RC declared a transmission emergency for Oct 23. The fires continue to burn with high winds expected till midday on Oct 24 and the fires are still threatening several transmission lines. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster – Brush Fire ACTIONS TAKEN: Shed Firm Load; Implemented a Warning, Alert, or Contingency Plan REPORT CRITERIA: OE-417 and EOP-004 DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy	Y	Y		Y	106
10/24/2007 9:45	N/A	Southern CA	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Public Appeal - Conservation	DESCRIPTION: On Oct 24, 2007 at 9:45 am, the Reliability Coordinator issued a public alert to conserve electricity if possible. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
10/24/2007 12:45	0.25	Southern CA	WECC-CAMX	Y	Y	N	PA	N/A	N/A	Public Appeal - Conservation	DESCRIPTION: On Oct 26, 2007 at 12:45 PM, the Reliability Coordinator issued a public alert to conserve electricity if possible. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Other ACTIONS TAKEN: Made Public Appeals REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	N	N	Public Appeal	Y	
10/26/2007 14:06	N/A	San Diego G&E	WECC-CAMX	Y	Y	N	UO	N/A	200	Fires - Brush Fires - Firm Load Shed	DESCRIPTION: On Oct 22 at 2:06 PM, the continuing brush fires in the region caused the tripping of two transmission lines in a neighboring utility resulting in the overload of another line. The Reliability Coordinator ordered the utility to shed 200 MW of firm load immediately to alleviate the overload. Service was restored to the 68,780 shed customers 37 minutes later. TYPE OF EMERGENCY: Other – Transmission system overload CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Shed Firm Load; Repaired/Restored REPORT CRITERIA: OE-417 DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy	N	Y		Y	
10/26/2007 6:45	3.75	Southern CA Breaker	WECC-CAMX	Y	Y	N	UO	N/A	280	Equipment Failure – Breaker	DESCRIPTION: On Oct 24, 2007 at 6:45 am, the utilities substation had a malfunction of a breaker or line and 280 MW was lost. All loads were restored at 10:30 am on Oct 26. TYPE OF EMERGENCY: Loss of 115/66 kV feeder CAUSE OF INCIDENT: Transmission Equipment ACTIONS TAKEN: Repair/Replace REPORT CRITERIA: OE-417 DOE #8 – Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system	Y	Y		Y	704
10/26/2007 14:01	0.35	City of Riverside	WECC-CAMX	Y	N	N	INT	90323	240	Fires - Line Load Limits Exceeded	DESCRIPTION: On Oct 26, 2007 at 2:01 PM two 230 kV lines relayed when brush fire burned under both lines. At 2:05 PM manual load shedding was initiated at two substations, due to a 230 kV line exceeding the 15 min emergency loading limit. Approx 90323 customers were affected. At 2:22, all substations were returned to normal service. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Unknown Cause ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	56
11/3/2007 18:00	24.00	Eastern MA, RI, Cape Cod	NPCC-ISO-NE	Y	Y	N	INT	170000	100	Weather - Tropical Storm Noel	DESCRIPTION: On Nov 3, 2007, at 6 PM, tropical storm (Noel) with high winds arrived in the North East areas. Subsequent distribution customer outages were widespread throughout the area. As of 10 PM on Nov 3, the total number of customers OOS due to weather related outages were 62843. The storm continued into Nov 4, electric service was interrupted and up to 170000 customers (500 MW) were affected. In addition to distribution outages, two bulk (230 kV) power system circuits were tripped and quickly restored. By Nov 5 at 11 am, about 75% of the service had been restored. TYPE OF EMERGENCY: Other CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Repaired/Restored REPORT CRITERIA: OE-417 and EOP-004-1 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	Y	Y		Y	1,608
11/4/2007 9:31	2.17	Hydro-Quebec Transenergie Area	NPCC-HQ	N	Y	N	INT	20000	1,039	Weather - Tropical Storm Noel	DESCRIPTION: On Nov 4, 2007, at 9:31 am, tropical storm Noel hit the eastern service area with strong winds and snow near a substation to a radial transmission corridor. At 7:04 am, two 161 kV power lines tripped with a lost of 20 to 30 MW of load. At 8:24 am, a second line tripped and the corridor remained synchronized to the main grid by only one line (one of the three lines of the corridor was already out before that trip). The second power line was reenergized two minutes later but tripped again immediately. The dispatcher reduced the power flows to the new in around 10 minutes. At 8:38 am, a third line tripped causing the separation of the corridor. On the main grid the frequency dropped to a min of 59.05 Hz and on the affected subsystem the frequency raised to a maximum of 64.75 Hz. After that initial swing the island was stabilized for a while but with some difficulties to maintain the voltage profile. At 9:31 am following a voltage variation, a large-use customer tripped 400 MW of load and the subsystem collapsed. A total load of 1039 MW was lost. The system restoration procedure was applied on the subsystem. The synchronization with the rest of the grid was completed at 11:41 am. The loads were mostly restored around noon. The rest of the load was restored later the same day by distribution crews. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: Implemented a Warning, Alert, or Contingency Plan; Repaired/Restored	Y	Y		Y	1,508

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
11/11/2007 18:00	20.0	BC Province Area	WECC-NWPP	Y	N	N	INT	244000	N/A	SPS Failure - Update Error	DESCRIPTION: On Nov 11, 207 at 8:59 am, Modesto Irrigation District was in the process of updating of the SPS software. The change-over initiated the shedding of 27 12 kV distribution breakers. A total of 88 MW of interruptible power was lost and approximately 30000 customers were affected for a period of 8 minutes. There was no final determination of action to be taken to prevent recurrence. TYPE OF EMERGENCY: Major Distribution System Interruption CAUSE OF INCIDENT: Unknown Cause ACTIONS TAKEN: Shed Interruptible Load REPORT CRITERIA: N/A – NERC EOP-004-1 Form, see OE-417 criteria DOE #6 – Load shedding of 100 Megawatts or more implemented under emergency operational policy	N	Y		Y	
11/12/2007 6:30	12.5	Oregon, WA , BC-CA	WECC-NWPP	Y	N	N	INT	100000	N/A	Weather - High Wind Gusts - Rain	DESCRIPTION: On Nov 12, 2007 at 6:30 am, high winds ranging from 80 to85 knots entered the area resulting in distribution damage and the loss of approx. 105 MW of load. The affected LSE's reported over 100000 customers being affected (OOS). TYPE OF EMERGENCY: N/A CAUSE OF INCIDENT: Weather or Natural Disaster ACTIONS TAKEN: N/A REPORT CRITERIA: OE-417 DOE #11 – Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
11/16/2007 14:55	0.20	MA Area	NPCC-ISO-NE	Y	Y	N	UO	N/A	N/A	Equipment Failure - Static Wire	DESCRIPTION: On Nov 16, 2007 at 2:55 PM, a static wire fell into the 345 kv switchyard and the 2X transformer and tripped the 1X and 2X transformers. Due to the trip of the transformers the DC switchyard loss power tripping phase 2, 1419 MW was OOS until 10:05 PM until crews had isolated the 1X and restored the 2X. The 1X transformer remains OOS and is not expected to return until the end of Dec at the earliest. No load was interupted as a result of the event. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: N/A ACTIONS TAKEN: N/A REPORT CRITERIA: OE-417 but No Criteria Noted	N	N	No FIRM demand interruption reported	Y	
11/27/2007 3:38	85.4	PacifiCorp Area	WECC-RMPA	Y	N	N	UO	N/A	N/A	Animal Contact Bird Droppings	DESCRIPTION: On Nov 27, 2007 at 3:38 PM, the RC reported that a 345-kV line (A), carrying 394 MW, relayed open due to a phase-to-ground fault. The line was back in service at 4:05 PM. Four minutes later, the line relayed open again due to a phase-to-ground fault. Within a minute of this happening, another 345-kV line (B), carrying 724 MW, relayed open, also due to a phase-to-ground fault. As a result of loss of both 345-kV lines, the 230/138 kV transformer overloaded and relayed out of service, resulting in a separation between buses. The Operator responded by phase shifting, cutting schedules and curtailing generation.. No customers were affected by these outages. Heavy flows were observed in the neighboring systems due to the separation. The Operator requested a 200 MW generation reduction because of high angles prior to closing the lines. Rainy/snowy weather was reported in the area. However, line patrols in the night failed to identify the locations of the faults. All 345 kV lines were restored back in service by 10:33 PM. On the following day, line patrols found heavily bird contaminated insulators.. The contaminated insulators were replaced on Nov 29 and 30. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Loss of Part or All of a High Voltage Substation or Switchyard ACTIONS TAKEN: N/A	N	N	No FIRM demand interruption reported	Y	
11/30/2007 23:49	89.2	PacifiCorp Area	WECC-RMPA	Y	N	N	UO	N/A	N/A	Animal Contact Bird Droppings	DESCRIPTION: On Nov 30 at 11:49 PM, the 345 kV line (A), carrying 391 MW, relayed open due to a phase-to-ground fault caused by bird contamination. The Operator responded by phase shifting, cutting schedules and curtailing generation. The Operator requested a 200 MW generation reduction to lower flows on the transmission system. At 11:56 PM, the 345 kV line (B), carrying 765 MW, relayed open also due to phase-to-ground fault caused by bird contamination. As a result of the loss of both 345 kV lines, the 230/138 kV transformer overloaded and tripped. At 0:10 am, the RC reported high flows across and requested the neighboring utility to adjust the phase shifters. All the 345 kV lines were back in service by 3:56 am. Subsequent line patrols found bird contaminated insulators. The contaminated insulators were replaced on Dec 3 and 4, 2007. No customers were affected by the Nov. 30th outages. TYPE OF EMERGENCY: Major Transmission System Interruption CAUSE OF INCIDENT: Loss of Part or All of a High Voltage Substation or Switchyard ACTIONS TAKEN: N/A REPORT CRITERIA: Region Format	N	N	No FIRM demand interruption reported	Y	

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
12/1/2007 0:30	N/A	western Oregon and southwest Washington coastal areas	WECC-CAMX	Y	Y	N	INT	40454	N/A	Weather - Wind and Rain Storm	DESCRIPTION: On 12/1/2007, utility crews worked all night to restore service to customers who were without power due to the severe wind and heavy rain brought on by the powerful storms that have hit and continue to hit the area. Winds have been recorded up to 129 miles per hour and 60 – 70 foot waves have been reported. – Currently 40,454 customers are without power. – High wind warnings remain in effect in the coastal areas. -- Crews from other areas are being brought to the coast to assist. – We expect it may be 3-4 days before power is substantially restored to these areas. – in the meantime, customers are being asked to remain indoors and avoid any downed lines. CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, Letter Report	N	Y		Y	
12/2/2007 10:00	225.5	Pacific Northwest Area	WECC-NWPP	Y	N	N	INT	33000	125	Weather - Wind and Rain Storm	DESCRIPTION: Storm event with wind gusts reported by as high as 124 MPH. Caused multiple outages resulting in outage to about 33,000 customer. Affected FIRM not INTERRUPTABLE CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, Letter Report	Y	Y		N	18,883
12/2/2007 11:00	3.25	New England Area	NPCC-ISO-NE	Y	Y	N	UO	N/A	N/A	Fuel Supply Problems - Gas Supply Interruption	DESCRIPTION: On Sunday, 12/2/2007, a utility reported an Actions During a Capacity Deficiency. Due to an ongoing fuel problems, at 11:00 am, the loss of approx 620 MW of on line capacity. At 2:15 PM, the action was cancelled as otherr generation became available. CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, Letter	N	N	No FIRM demand interruption reported	Y	
12/3/2007 7:22	8.62	Mid Atlantic/ VA area	SERC-VACAR	Y	Y	N	UO	N/A	N/A	Equipment Failure - Switch	DESCRIPTION: On 12/3/2007, the utility facility experienced an electrical disturbance that resulted in both units (115.5 MW total, 107 MW operating at time) to trip off-line. The local utility at the time was setting up to do switching in preparation for outage work of a transmission line. The switch failed; the breakers were closed and generation restored. CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, EOP-004-1	N	N	No FIRM demand interruption reported	Y	
12/10/2007 3:08	220.87	Tulsa, OK	SPP	Y	Y	N	INT	256663	800	Weather - Ice Storm	DESCRIPTION: The utilities meteorologist issued a freezing rain weather alert for the service area starting 12/9/2007 Sunday night through the following Tuesday morning. Icing began to be noticeable starting Sunday evening continuing through Tuesday morning. The customer outage history peaked at 256,663 on 12/10 evening / 12/11 morning. The amount of demand lost is estimated to be in the neighborhood of 800 Mw based on load forecast vs the actual load for 12/10. Generation capacity was not taken off line due to the reduced load during the ice storm. As of 12/10 only 6,000 customers were without service and were in the process of being restored. The utility did not loose any generation during the freezing rain event. The control area coordinators in conjunction with the Regional RC monitored the bulk system using security analysis programs. Contingencies were controlled through the TLR process. The utility experienced RTU communication failures on the bulk system on 12/10/2007. Bulk transmission line circuits outagges were reported to DOE. Weather permitting, aerial patrols were used to access the damage to the transmission lines. CAUSE/ACTION: Transmission equipment; repair and restore. THRESHOLD CRITERIA: #11. Loss of electric service to more than 50,000 customers for 1	Y	Y		N	118,385
12/10/2007 9:12	3.30	New England Area	NPCC-ISO-NE	Y	Y	N	UO	N/A	N/A	Equipment Failure - Dedicated Path Logic	DESCRIPTION: The Dedicated Path Logic (DPL) SPS mis-operated at approximately on 12/10/2007 at 9:12 am.. The mis-operation was traced to an SPS logic problem that allowed a line out condition to be satisfied by opening only one of two terminal breakers. The logic scheme was corrected and successfully tested at 12:30 on 12/10. At the time of the misoperation, no generation was armed and there was no system impact. CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, EOP-004-1 Reported	N	N	No FIRM demand interruption reported	Y	
12/11/2007 4:00	227.50	Eastern half of the state of Kansas	SPP	Y	Y	N	INT	95000	500	Weather - Ice Storm	DESCRIPTION: Severe wind and ice storms moved through the service area the evening of 12/10/ 2007. By approximately 4:30 am on 12/11 more than 50,000 customers were outaged. As of 12:30 on 12/11, approximately 87,000 customers were outaged. By 12/20 3:30 PM -- the utility said it will have power restored by day's end to all customers who are able to receive electrical service. The utility will continue to restore power to customers as they become ready and to fix streetlights and perform other clean-up work. More than 2,000 linemen from 21 states, and more than 1,200 tree trimmers, joined 1,200 utility employees who were dedicated to restoring power and support the work of the tree trimming and line crews. At the peak of the incident, more than 2000 MW of generation were out of service. CAUSE/ACTION: Weather or Natural Disaster. THRESHOLD CRITERIA: DOE# 11.Loss of electric service to more than 50,000 customers for 1 hour or more.	Y	Y		N	76,213
12/12/2007 1:49	0.17	ERCOT area	ERCOT	Y	Y	N	UO	N/A	N/A	System Protection	DESCRIPTION: .On 12/12/2007 at 1:49 am the utility simultaneous lost 846 MW of GT and a 176 MW generator. This was a potential NERC Disturbance Control Standard event. The reason for the trip is under investigation. The utility employed redistribution as responsive reserve service to recover frequency. Frequency recovered in 10 minutes. CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, EOP-004-1 Reported	N	N	No FIRM demand interruption reported	Y	

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2009 Value Proposition
Improved Reliability Benefit - NERC Database

Disturbance Start Date & Time	Disturbance Duration (Hours)	Associated Utilities	Region ID	In U.S. Region?	In RTO Region?	In MISO Region?	Disturbance Type	Customers Interrupted	Disturbance Size (MW)	Disturbance Cause	Event Description	Primary Filter	Secondary Filter	Secondary Filter: If No, Why Not?	Threshold Filter	MWh Interrupted
12/12/2007 8:55	2.1	Arizona-New Mexico	WECC-AZNMSNV	Y	N	N	UO	N/A	N/A	Equipment Failure - Breaker Fault	DESCRIPTION: On 12/12/2007 at 8:55 am, a 500-kV breaker 942 faulted internally in the A phase tank. The fault occurred during a routine open operation that was taking place for a scheduled outage. This fault cleared the 500-kV east bus with a bus differential relay operation. 500-kV line #3 was cleared due to the bus differential relaying tripping PL 982 and the resulting transfer tripping of the associated power breakers 912 & 915. There was no customer load loss associated with this event. CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, WECC Report	N	N	No FIRM demand interruption reported	Y	
12/13/2007 11:23	0.32	ConEd and PSE&G	RFC	Y	Y	N	UO	N/A	N/A	Equipment Failure - Feeder Fault	DESCRIPTION: On 12/13/2007 at 11:23am a multiple transmission feeder tripout occurred resulting in the loss of 2 transmission feeders, 345KV feederY94 and 138KV feeder 95891. Additionally 345KV feeder 69 (an inter-utility tie) opened automatically at the Ramapo S/S only and remained energized from PSEG 's Waldwick S/S. In addition 345KV feeder W72 opened automatically at the Ladentown S/S terminal only and automatically re-closed. This tripout resulted in a LTE violation on feeder K3411 in the PSE&G service area. Corrective actions were implemented by the NYISO. Note: This tripout occurred during snow/sleet CAUSE/ACTION: N/A THRESHOLD CRITERIA: NONE, EOP-004-1 Reported	N	N	No FIRM demand interruption reported	Y	
12/16/2007 1:00	120.45	Eastern Pennsylvania	RFC	Y	Y	N	INT	176000	N/A	Weather - Ice Storm	DESCRIPTION: On Sunday, 12/16/2007 the utility was impacted by a significant winter storm event, which included high winds and freezing rain with up to 1.5" of ice accumulation. This resulted in widespread damage to equipment within the service territory. The damage included downed wire and poles due to the excessive weight of the ice as well as trees fallen into facilities. This event was further hampered by continued sub-freezing weather, which made it difficult to access and remove ice from downed lines and equipment. Mutual assistance was provided other utilities, as well as contractors, including 196 Forestry Workers and 419 Line Workers, in addition to the 200 Line Workers from the affected utility. CAUSE/ACTION: Weather or Natural Disaster. THRESHOLD CRITERIA: DOE# 11.Loss of electric service to more than 50,000 customers for 1 hour or more	N	Y		Y	
12/22/2007 2:52	1.25	Eastern Region of ERCOT	ERCOT	Y	Y	N	UO	N/A	N/A	Equipment Failure	DESCRIPTION: With frequency initially at 59.949 Hz at 02:52:46, the North DC Tie tripped due to reactive switching at the station. CAUSE/ACTION: Implemented a Warning, Alert, or Contingency Plan; Shed Interruptible Load THRESHOLD CRITERIA: DOE #6-Load shedding of 100 Megawatts or more implemented under emergency operational policy	N	N	No FIRM demand interruption reported	Y	
12/23/2007 1:00	12.00	Entire ComEd service territory.	RFC	Y	Y	N	INT	69000	N/A	Weather - Ice Storm	DESCRIPTION: Severe wind storms moved through the service area. CAUSE/ACTION: Weather or Natural Disaster. THRESHOLD CRITERIA: DOE# 11.Loss of electric service to more than 50,000 customers for 1 hour or more.	N	Y		Y	

ATTACHMENT 9

Midwest ISO
Energizing the Heartland

2009 Value Proposition
LBA Unloaded Capacity Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$152	$161	$186	$1,166
High Estimate ($ in Mils.)	$161	$170	$196	$1,233

Assumptions	
Annual Inflation Rate	2.90% [1]
Discount Rate	9.50% [2]

Calculation Detail ($ in Mils.)

	A	B	C	D	E	F		
Year	Increase in Offered Economy Max (MW) from 2006 to 2009 [3]	2009 Average Regulation (MW) [4]	2009 Average Spinning Reserves (MW) [5]	LBA Unloaded Capacity Reduction (MW) A - B - C	Production Costs Savings per MW Low Estimate [6]	Production Costs Savings per MW High Estimate [6]	Benefit Low Estimate D X E	Benefit High Estimate D X F
2009	1,933	429	873	631	$0.240701	$0.254588	$152	$161
2010	1,933	429	873	631	$0.247681	$0.261971	$156	$165
2011	1,933	429	873	631	$0.254864	$0.269568	$161	$170
2012	1,933	429	873	631	$0.262255	$0.277385	$165	$175
2013	1,933	429	873	631	$0.269861	$0.285429	$170	$180
2014	1,933	429	873	631	$0.277687	$0.293707	$175	$185
2015	1,933	429	873	631	$0.285739	$0.302224	$180	$191
2016	1,933	429	873	631	$0.294026	$0.310989	$185	$196
2017	1,933	429	873	631	$0.302553	$0.320008	$191	$202
2018	1,933	429	873	631	$0.311327	$0.329288	$196	$208

The LBA Unloaded Capacity benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

Midwest ISO
Energizing the Heartland

2009 Value Proposition
LBA Unloaded Capacity Benefit

Sources

[1] 2.9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators. Annual Growth 2007-2030 (percent). Wholesale Price Index (1982-1.00). Fuel and Power.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] Increase in offered economy max represents increase in available generation for baseload units only.

[4] Post-ASM Regulation (MW) from Midwest ISO Monthly Operations Report, August 2009

Jan-09	534
Feb-09	463
Mar-09	438
Apr-09	420
May-09	392
Jun-09	398
Jul-09	396
Aug-09	394
Post-ASM Average	**429**

[5] Post-ASM Spinning Reserves (MW) from Midwest ISO Monthly Operations Report , August 2009

Jan-09	939
Feb-09	907
Mar-09	888
Apr-09	857
May-09	829
Jun-09	849
Jul-09	853
Aug-09	862
Post-ASM Average	**873**

[6] Production Cost Savings per MW

Year	Inflation Rate	Production Cost Savings per MW ($ in Mils.) - Low	Production Cost Savings per MW ($ in Mils.) - High
2008	N/A	$0.260000	$0.275000
2009	-7.4%	$0.240701	$0.254588

Note #1 - Inflation Rate from Actual PPI from Bureau of Labor Statistics based on Electric Power Generation industry. Actual PPI for 2009 is thru August 2009 only. Actual PPI thru August 2009 was assumed to be indicative of the Actual PPI for the entire 2009 year.

Note #2 - Production Cost Savings per MW based on Midwest ISO production cost modeling performed in 2008.

Note #3 - Beyond 2009, Production Cost Savings per MW was adjusted by the annual inflation rate of 2.9%.

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ATTACHMENT 10

Midwest ISO Issues Value Proposition for 2009

Study shows that Midwest ISO provides $700-$900M in annual economic benefits to its region

FOR IMMEDIATE RELEASE
December 4, 2009

MEDIA CONTACT
Midwest ISO Media: 317-432-4507

Carmel, IN – Midwest Independent Transmission System Operator Inc. (Midwest ISO) has revised its Value Proposition. The revised study calculates the value provided through improved grid reliability and increased efficiencies in the use of generation resources enabled by the Midwest ISO market operations. For 2009, these efforts provide the Midwest ISO region with net benefits of between $700 and $900 million. Over the next ten years, the region will receive between $5.5 and $7.1 billion in benefits on a net present value basis.

The study also identified additional potential annual benefits of between $525 and $660 million from the deferral of generation investment. However, these benefits are dependent on either future load growth from the recovering economy or generation loss from factors such as increasing environmental restrictions and aging infrastructure.

"We have updated the Midwest ISO Value Proposition to demonstrate the progress we've made in providing economic benefits through increased efficiency and improved operations," said John Bear, President and CEO of the Midwest ISO. "This year, our region saved hundreds of millions of dollars as a result of increased reliability provided through our transparent wholesale energy market."

In addition to quantitative benefits, the Midwest ISO has demonstrated as part of its Value Proposition significant qualitative benefits that wholesale market participants receive. These include benefits for price transparency, planning coordination, regulatory compliance and wholesale platforms that integrate larger quantities of renewable energies like wind and solar with the smart grid

"The improvements associated with the Value Proposition indicate that we are making progress toward increasing the performance of our market," said Bear. "The Midwest ISO's energy market provides the Midwest ISO with a wholesale smart grid – a platform on which we will continue to build and provide value."

The full 2009 Value Proposition is available online at **www.midwestmarket.org.**

About the Midwest ISO
Midwest ISO ensures reliable operation of, and equal access to miles of interconnected, high-voltage power lines in 13 U.S. states and the Canadian province of Manitoba. The Midwest ISO manages one of the world's largest energy markets, clearing nearly $41 billion in energy transactions annually. The Midwest ISO was approved as the nation's first regional transmission organization (RTO) in 2001. The non-profit 501(C)(4) organization is governed by an independent Board of Directors, and is headquartered in Carmel, Indiana, with operations centers in Carmel and St. Paul, Minnesota. Membership in the organization is voluntary. For more information, visit www.midwestmarket.org.

ATTACHMENT 11

Midwest ISO
Energizing the Heartland

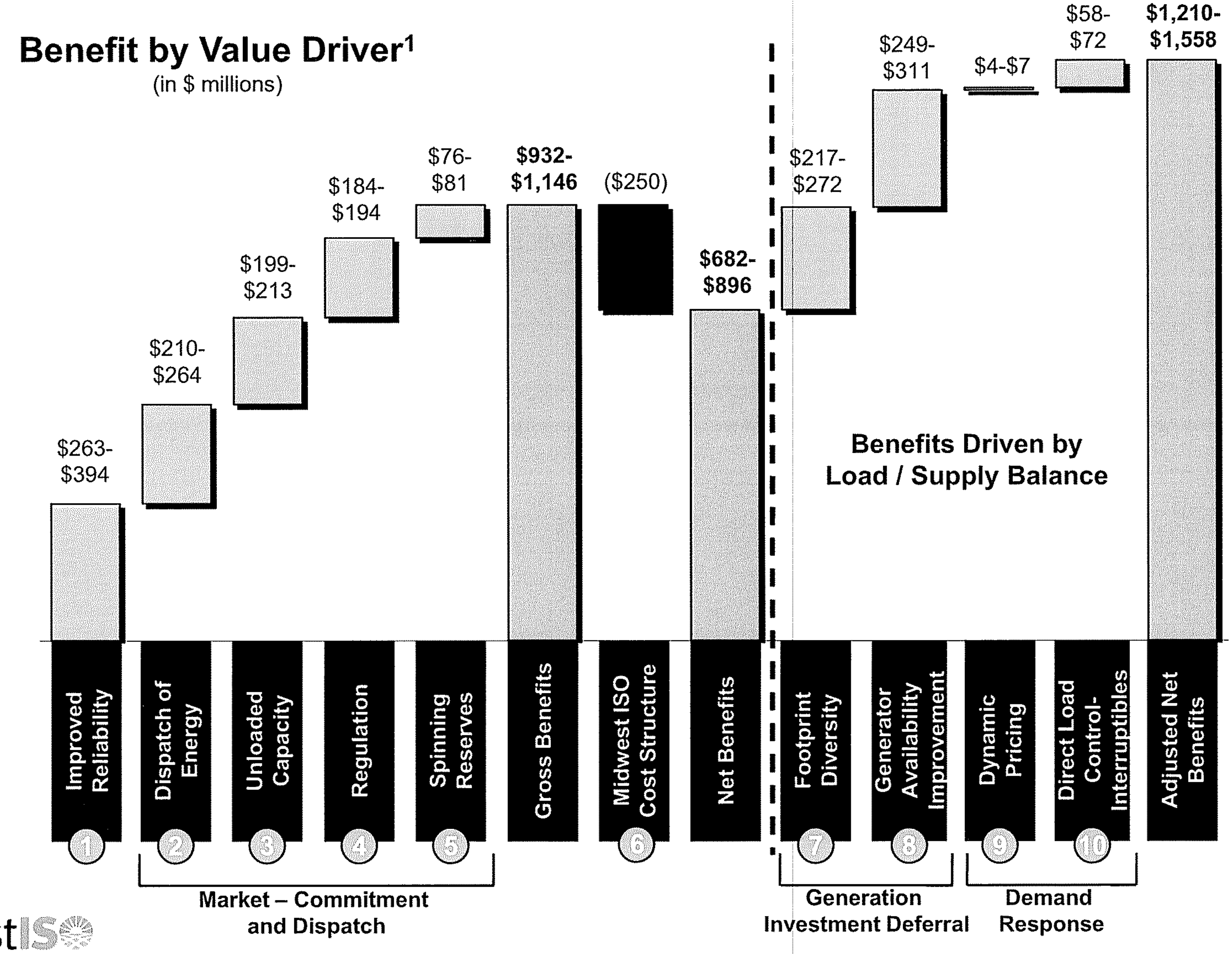
Midwest ISO
Value Proposition

The Midwest ISO Value Proposition is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

Carmel, IN

December 3, 2009

The Midwest ISO 2009 Value Proposition



MidwestISO
Energizing the Heartland

[1]Figures shown reflect annual benefits and costs that can be expected in 2009

Attachment 11 of Item KIUC MISO 1-2
Page 2 of 31

Midwest ISO's operating practices exceed industry standards allowing enhanced reliability in its footprint

1 Improved Reliability

	Industry Standard Practice	Midwest ISO Practice
System Monitoring and Visualization	▸ Real-time monitoring using SCADA on a local area basis	▸ Regional view/monitoring of the power system including: ▸ A state estimator - runs every 90 seconds ▸ Contingency analysis of over 7,500 contingencies every five minutes ▸ 24-hour shift engineer coverage responsible for maintaining security application performance
	▸ Use of standard vendor supplied displays	▸ Extended use of custom tools and displays to allow for faster analysis and better situational awareness
	▸ Operator interface of standard monitor display screen augmented with static mapboard	▸ Large video wallboard (14' X 165') that provides operators with live data reflecting the state of the power system and real-time market results
	▸ Ad-hoc and off-line voltage security analysis review	▸ Performs multiple voltage security analysis daily during intra-day and next day planning
Congestion Management	▸ Performed using NERC Transmission Loading Relief (TLR) process or internally developed operating procedure based on congestion management system ▸ 30 – 60 minute response time	▸ Market-based congestion management that relies on a five-minute security constrained economic dispatch to mitigate transmission congestion on a least-cost basis allows for more timely and efficient congestion management ▸ Seams management operated via agreed upon methodologies with border companies
Back-up Capabilities	▸ Off-line and/or scaled down back-up facility	▸ On-line back-up facility with full coverage of power system and market applications
	▸ Significant time to bring facility up in the event failover or failback is needed	▸ Less than 10 minutes required for failover or failback for critical applications
	▸ Testing of failover process is performed annually	▸ Testing of failover process is performed bi-monthly for critical applications

Midwest ISO's operating practices exceed industry standards allowing enhanced reliability in its footprint (cont'd)

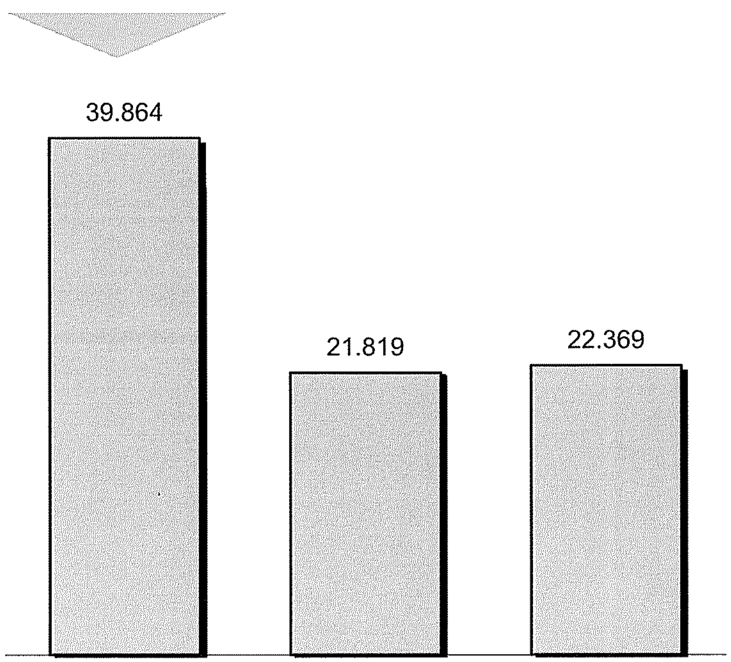
1 Improved Reliability

	Industry Standard Practice	Midwest ISO Practice
Operator Training	‣ Classroom training only	‣ Training methods include extensive use of full dispatch training simulator
	‣ Train to meet minimum NERC requirements	‣ Training exceeds NERC requirements
	‣ Five-person rotation (no training rotation)	‣ Six-person rotation at key operator positions (allowing a training week during each cycle)
	‣ Off-line power system restoration procedure review	‣ Annually conduct a regional "live" power system restoration drill that includes dozens of companies in the region
Performance Monitoring	‣ Performance reviewed on a "post-event" basis	‣ Daily review of operational performance including: ‣ Extensive review of established operational metrics ‣ Monthly tracking of improvements ‣ Frequent near-term performance feedback to operators and support personnel
	‣ Operator call review on a "post-event" basis	‣ Standardized operator call review process incorporating established metrics that score calls for each operator on a routine basis ‣ Feedback provided to each operator
Procedure Updates	‣ Procedures updated on an ad-hoc, as-needed basis	‣ Annual procedure review conducted on all control room procedures ‣ Routine drills including member participation conducted on capacity emergency procedures

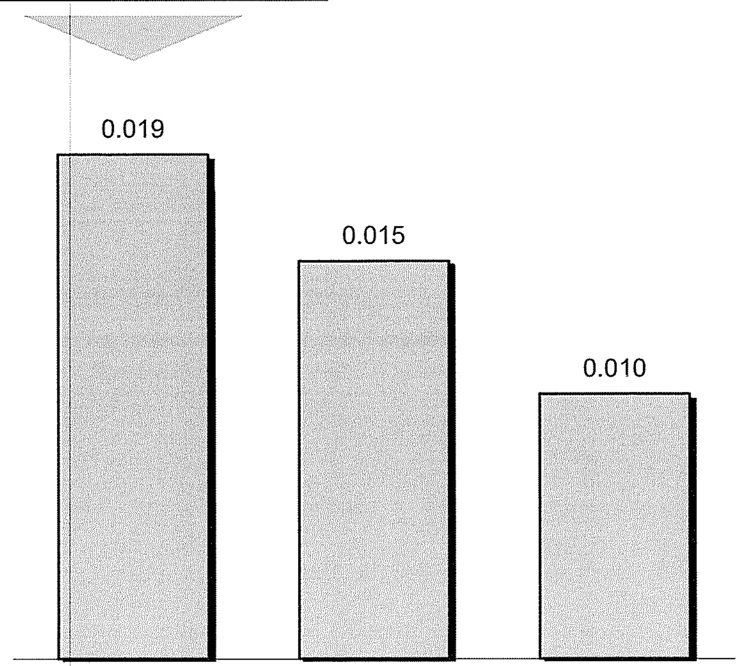
The improved reliability of the RTO model (and the Midwest ISO in particular) can be measured by applying standard industry metrics to the transmission system

1 Improved Reliability

System Average Interruption Duration Index (SAIDI)[1,3,4]



System Average Interruption Frequency Index (SAIFI)[2,3,4]



[1]*SAIDI* = $\frac{\textit{Customer Minutes Out}}{\textit{Number of Customers}}$ [2]*SAIFI* = $\frac{\textit{Customer Interruptions}}{\textit{Number of Customers}}$

[3]*Data collected from: (a) NERC, 2000-2007 Disturbance Data (transmission based outages only), (b) Energy Information Administration, 2000-2007 Disturbance Data (transmission based outages only), and (c) Energy Information Administration, EIA-826 Database*

[4]*Midwest ISO's reliability footprint prior to 1/1/2009 was used for these calculations.*

A similar metric can be used to evaluate the value of that improved reliability

1 Improved Reliability

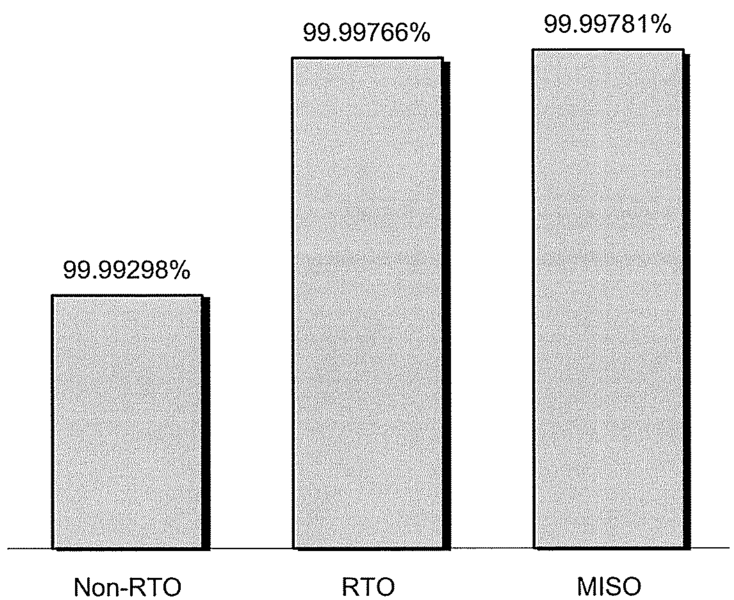
Reliability Benefit = ① **Transmission System Availability Index (TSAI)** × ② **Midwest ISO Load** × ③ **Cost of Outage**

- ① Transmission System Availability Index (TSAI): Measured as a %
- ② Midwest ISO Load: Measured in MWh
- ③ Cost of Outage: Measured in $ per MWh

Analysis of NERC outage information reveals that RTO regions serve their load more reliably …

1 Improved Reliability

1 **Transmission System Availability Index (TSAI)[1,3,4]**



TSAI Formulas

$$\textbf{TSAI} = 1 - \left(\frac{\text{Sum of MWh Load Interrupted}}{\left(\text{Sum of MWh Load Interrupted} + \text{Sum of MWh Load Served} \right)} \right)$$

Sum of MWh Load Interrupted =

$$\sum_{\#\text{ of disturbances}}^{1} \left(\begin{array}{l} \text{Duration (hrs) X} \\ \text{Disturbance Size (MW) X} \\ \text{Load Loss Recovery Factor}^{2}\ (0.67) \end{array} \right)$$

[1]*Disturbances with outages exceeding 1,000,000 customers and/or outage durations longer than one week were excluded from the analysis as it was assumed those characteristics fit the profile of a distribution-level event*

[2]*The Load Loss Recovery Factor is used to account for the progressive recovery of load during an outage.*

[3]*Data collected from: (a) NERC, 2000-2007 Disturbance Data (transmission based outages only), (b) Energy Information Administration, 2000-2007 Disturbance Data (transmission based outages only), and (c) Energy Information Administration, EIA-826 Database*

[4]*Midwest ISO's reliability footprint prior to 1/1/2009 was used for these calculations*

Midwest ISO Energizing the Heartland

…providing between $263 and $394 million in annual benefits to the region

1 Improved Reliability

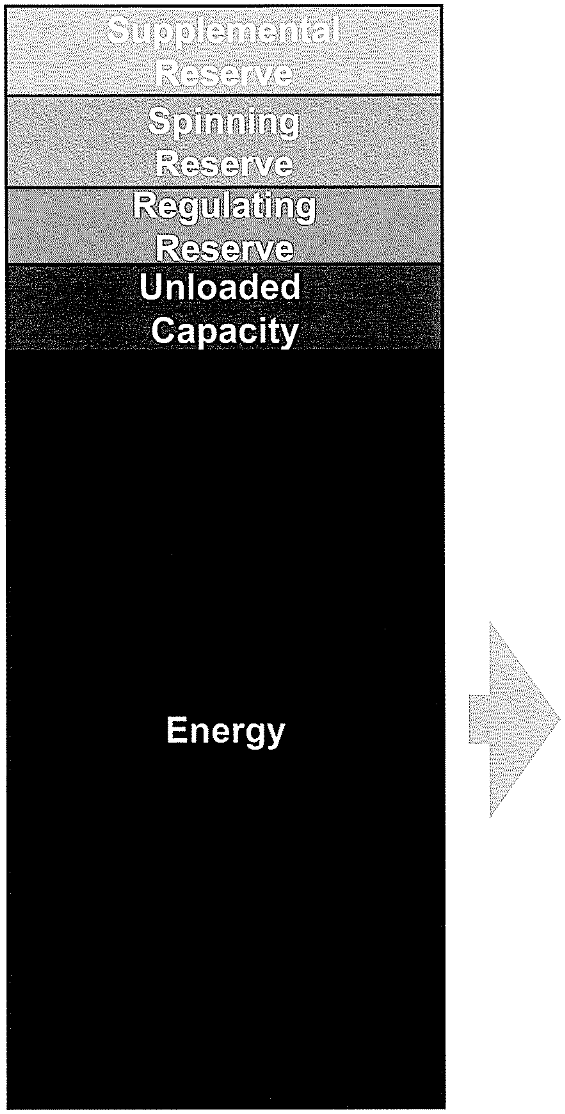
		Reliability Benefit Low Estimate	Reliability Benefit High Estimate
	1 Transmission System Availability Index (TSAI)	RTO 99.99766% Non-RTO 99.99298% Difference 0.00468%	RTO 99.99766% Non-RTO 99.99298% Difference 0.00468%
×	2 Midwest ISO Load[1]	647,538,321 MWh	647,538,321 MWh
×	3 Cost of Outage	\$8,666 per MWh[2]	\$12,999 per MWh[2]
=	Reliability Benefit (\$ in Mils.)	**\$263**	**\$394**

[1]Energy Information Administration, EIA-826 Database, 2008
[2]ICF, "The Economic Cost of the Blackout." The ICF paper defined a cost of outage range to be 80 to 120 times the retail price of electricity. This range is supported by survey-based studies that estimate an electric consumer's (i.e. residential, commercial, industrial, and others) willingness-to-pay to avoid such outages. The retail price was adjusted to 2009 dollars using Actual CPI from the Bureau of Labor Statistics.

Midwest ISO
Energizing the Heartland

The Energy Market provides the region with a more efficient means of committing/dispatching generation

2 Dispatch of Energy



Historical Perspective

- Prior to the Midwest ISO's creation, the region operated as a decentralized, bilateral market. Transmission operations and bilateral power transactions were characterized by physical transmission constraints managed through mechanisms that limited transmission utilization, high transaction costs, low market transparency, pancaked transmission rates, decentralized unit commitment and dispatch.

What Changed with the Midwest ISO?

- The Midwest ISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers provided by Market Participants. The day-ahead market is a forward financial market for energy and its clearing process produces a set of financially binding schedules according to which sellers are financially responsible to deliver and purchasers are financially responsible to buy energy at defined locations. The day-ahead market process is based upon a unit commitment model that minimizes total production costs over 24 hours. The primary purpose of the day-ahead market is to clear and schedule sufficient supply to satisfy cleared day-ahead demand, using a set of resources that minimize production costs. 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 dynamically.

Benefit Calculation Methodology

- This benefit is best modeled by using an industry standard technique called production cost modeling. Analysis by a number of independent firms has consistently found that a market, such as the Midwest ISO's, that centrally commits and dispatches generation for a large region will be more cost-efficient than dividing that same generation portfolio into a number of sub-regions and then committing and dispatching them.

The improved commitment and dispatch provide between $210 and $264 million in annual benefits

Study Assumptions

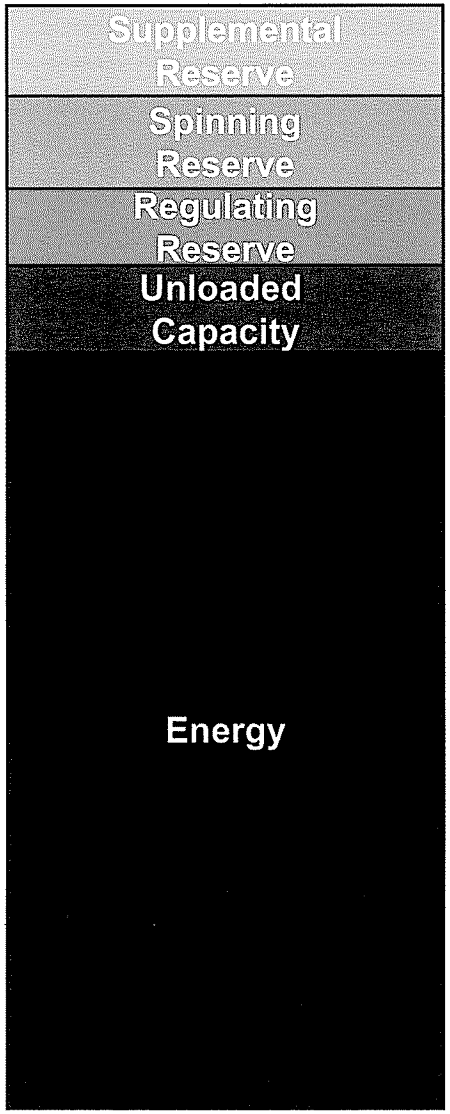
- Modeled based on Midwest ISO Commercial and Network Model
- Analysis performed in PROMOD®
- Pre-Midwest Market Analysis
  - Transmission system utilization was derated (e.g., less than 100% transmission utilization)
  - Hurdle rates between control areas were calibrated individually to match historical dispatch
- Post-Midwest Market Analysis
  - Transmission system utilization could reach 100%
  - Hurdle rates between control areas were eliminated

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[1,2,3] ($ in Mils.)	$210	$222	$257	$1,613
High Estimate ($ in Mils.)	$264	$280	$323	$2,028

[1]ICF, "Independent Assessment of Midwest ISO Operational Benefits", 02/07/2007. The ICF study examined market performance from 06/2005 to 08/2006. To account for market maturity, our analysis only considered data for 2006 and annualized the results. The 2006 results were annualized assuming that benefits would accrue at the same rate from September through December. The low estimate uses actual benefits achieved while the high estimate uses theoretical maximum potential benefits as defined in the ICF study.
[2]All figures adjusted to 2009 dollars using Actual PPI (Electric Power Generation Industry) from Bureau of Labor Statistics
[3]Midwest ISO's market footprint prior to 9/1/2009 was used for these calculations
Note: There have been other studies that have quantified the dispatch of energy benefit. The most recent study is "Generation Cost Savings From Day 1 and Day 2 RTO Market Designs" by The Brattle Group published October 1, 2009. The study estimates Midwest ISO-wide savings of $261 million per year in fuel and SO2 costs associated with the full transition from Day 0 to Day 2.

The Ancillary Services Markets allowed both the Midwest ISO and the former Balancing Authorities to reduce unloaded capacity

3 Unloaded Capacity



Historical Perspective

- Unloaded capacity is defined as the amount of capacity that is committed to meet energy needs that is in excess to the peak demand. There are three primary drivers of unloaded capacity:
  1. Natural outcome of the step function associated with committing a unit to meet the next increment of demand that exceeds the sum of the capacities of the units already committed;
  2. Inaccurate forecast of peak demand; and
  3. Decision by the operator (Balancing Authority or Market Operator) to commit additional capacity in order to be prepared to deal with operating issues that may occur during the day.

What Changed with the Midwest ISO?

- With the start of the Midwest Markets, the amount of unloaded capacity associated with Driver 1 dropped significantly. With the commitment process centralized in the Midwest ISO, the unloaded capacity associated with commitment "blockiness" was only incurred once for the region instead of once for each Balancing Authority (BA). The savings associated with this driver are included in the Dispatch of Energy calculation and are NOT included in this calculation.
- With the start of the Ancillary Service Markets and the functional consolidation of BAs, responsibility to respond to operating issues was consolidated in the Midwest ISO. Therefore, the need for multiple BAs to commit capacity to deal with these issues was eliminated.

Benefit Calculation Methodology

- This calculation is a two-step process. The first step is to look at the change in unloaded capacity committed by the Midwest ISO and to value it based on the differences in average production cost with and without that commitment. The second step is to identify the change in individual unit capacities made available to the market. This is done by looking at the offers submitted, specifically by looking at changes in the Economic Max of the units and adjusting for Regulation and Reserves being held. Any increase in capacity in these low cost units is available for energy dispatch and is valued through production cost modeling.

Midwest ISO
Energizing the Heartland

The Midwest ISO has reduced its unloaded capacity by 51% resulting in an annual benefit of $47 to $52 million

3 Unloaded Capacity

Assumptions	
Early Market Operating Unloaded Capacity[1]	691.7 MW
Post-ASM Operating Unloaded Capacity[2]	337.8 MW
Production Cost Savings per MW per year[3]	$133,066 – Low Case $147,073 – High Case
Wholesale Price Index – Fuel & Power[4]	2.9%
Discount Rate	9.50%

Calculation Methodology

- Calculation is based on difference between Early Market and Post-ASM Operating Unloaded Capacity multiplied by the Production Cost Savings per MW per year
- Production Cost Savings per MW were adjusted each year by the Fuel & Power Wholesale Price Index while the Early Market and Post-ASM Operating Unloaded Capacity difference was held constant

Midwest ISO Operating Unloaded Capacity Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[5] ($ in Mils.)	$47	$50	$58	$362
High Estimate ($ in Mils.)	$52	$55	$64	$400

[1] *Average unloaded capacity (Dec. 2006 – Nov. 2007) per Midwest ISO Monthly Operations Reports from Dec. 2007 to Nov. 2008*

[2] *Average unloaded capacity (Jan. 2009 – September 2009) per Midwest ISO Monthly Operations Report for September 2009*

[3] *Based on Midwest ISO production cost modeling*

[4] *EIA 2009 Annual Energy Outlook*

[5] *Midwest ISO's market footprint prior to 9/1/2009 was used for these calculations*

Midwest ISO
Energizing the Heartland

Generators have also increased the amount of capacity available on their baseload units, resulting in annual benefits of $152 to $161 million

Assumptions	
Economy Max Change – Baseload Units[1]	630.6 MW
Production Cost Savings per MW per year[2]	$240,701 – Low Case $254,588 – High Case
Wholesale Price Index – Fuel & Power[3]	2.9%
Discount Rate	9.50%

Calculation Methodology

- Calculation is based on increase in available baseload generation multiplied by the Production Cost Savings per MW per year
- Production Cost Savings per MW were adjusted each year by the Fuel & Power Wholesale Price Index while the Early Market and Post-ASM Operating Unloaded Capacity difference was held constant

LBA Operating Unloaded Capacity Benefit

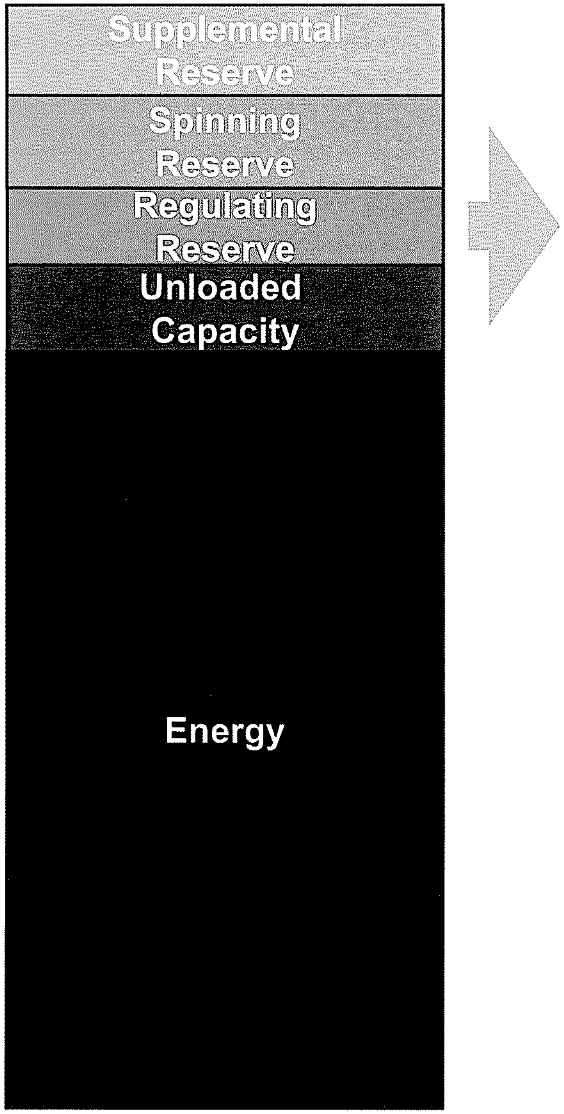
	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[4] ($ in Mils.)	$152	$161	$186	$1,166
High Estimate ($ in Mils.)	$161	$170	$196	$1,233

Total of Midwest ISO and LBA Operating Unloaded Capacity Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$199	$211	$244	$1,528
High Estimate ($ in Mils.)	$213	$225	$260	$1,633

[1]Midwest ISO Study – Change in offered Economy Max after 1/6/2009, adjusted for regulation and reserve changes due to ASM
[2]Based on Midwest ISO production cost modeling
[3]EIA 2009 Annual Energy Outlook
[4]Midwest ISO's market footprint prior to 9/1/2009 was used for these calculations

Ancillary Service Markets have resulted in reduced Regulation requirements and improved commitment and dispatch efficiency



Historical Perspective

- Prior to the launch of the Midwest ISO's Regulation Market, each Balancing Authority (BA) maintained regulation within their area. This often resulted in the BAs within the Midwest ISO footprint working "against" each other – some regulating up with others regulating down.

What Changed with the Midwest ISO?

- With the start of the Midwest ISO's Regulation Market, the amount of regulation required within the Midwest ISO footprint has dropped significantly. This is a result of working towards a centralized common footprint regulation target rather than a number of non-coordinated regulation targets within the footprint.
- The implementation of the Regulation Market also changed the pricing mechanism for Regulation by moving from tariff pricing to market pricing. This pricing change is not a true benefit from an economic perspective and, therefore, is not included in the Value Proposition. The affects of the new pricing mechanism for Spinning Reserves are tracked and reported in the Midwest ISO's monthly Market Operations Report.

Benefit Calculation Methodology

- The reduced requirements for regulation also frees up low cost generation units (where regulation was previously held) to serve the energy needs of the region. This component is valued using production cost analysis.

Those Regulation-related improvements result in between $184 and $194 million in annual benefits

Assumptions	
Pre-ASM Average Regulation[1]	1,188.0 MW
Post-ASM Average Regulation[2]	425.6 MW
Production Cost Savings per MW per year[3]	$240,701 – Low Case $254,588 – High Case
Wholesale Price Index – Fuel & Power [4]	2.9%
Discount Rate	9.5%

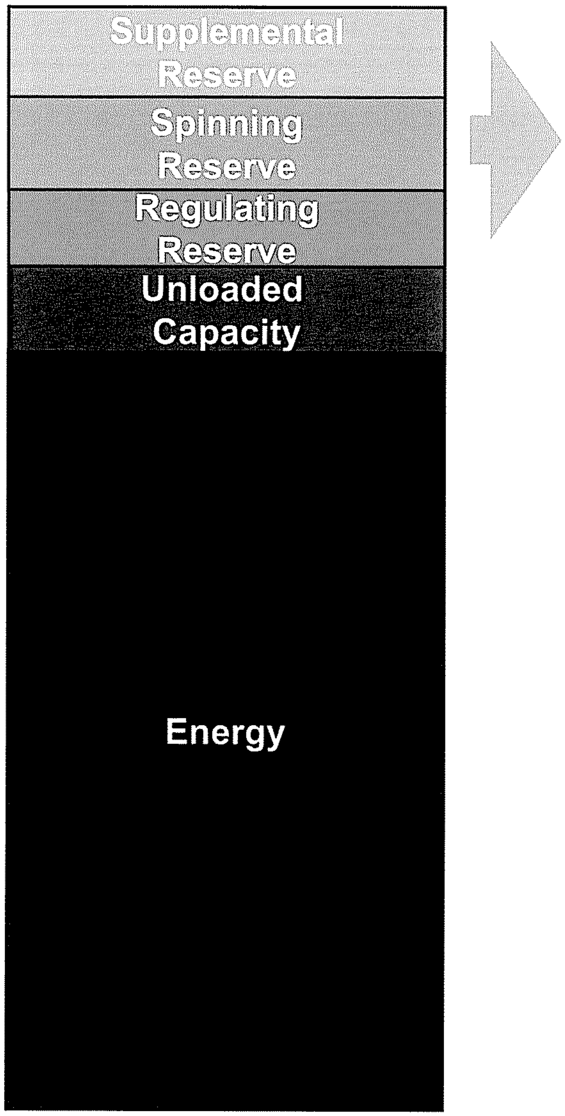
Calculation Methodology

- Calculation based on difference between Pre-ASM and Post-ASM Regulation multiplied by the Production Cost Savings per MW per year
- Production Cost Savings per MW were adjusted each year by the Fuel & Power Wholesale Price Index while the Pre-ASM and Post-ASM Regulation difference was held constant

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[5] ($ in Mils.)	$184	$194	$224	$1,409
High Estimate ($ in Mils.)	$194	$206	$237	$1,491

[1]Average daily regulation (4/1/2005-12/31/2008) supplied by Balancing Authorities
[2]Average monthly regulation (Jan. 2009 – September 2009) per Midwest ISO Monthly Operations Report for September 2009
[3]Based on Midwest ISO production cost modeling
[4]EIA 2009 Annual Energy Outlook
[5]Midwest ISO's market footprint prior to 9/1/2009 was used for these calculations

Similarly, the ASM has resulted in reduced Spinning Reserve requirements and improved efficiency



Historical Perspective

Pre-Contingency Reserve Sharing Group (CRSG)

- Each Balancing Authority (BA) determined their spinning reserve requirement based on their individual (or Reserve Sharing Group) standards

Post-CRSG/Pre-Ancillary Services Market (ASM)

- Each BA determined their spinning reserve requirement based on the CRSG standards

Post-ASM

- Midwest ISO determines their spinning reserve requirement based on Midwest CRSG requirements.

What Changed with the Midwest ISO?

- Starting with the formation of the CRSG and continuing with the implementation of the Spinning Reserve Market, the total spinning reserve requirement has been reduced. It is currently reduced by over 25% from pre-CRSG requirements. This reduced requirement frees up low cost capacity to meet energy market needs.
- The implementation of the Spinning Reserve Market also changed the pricing mechanism for Spinning Reserves by moving from tariff pricing to market pricing. This pricing change is not a true benefit from an economic perspective and, therefore, is not included in the Value Proposition. The affects of the new pricing mechanism for Spinning Reserves are tracked and reported in the Midwest ISO's monthly Market Operations Report.

Benefit Calculation Methodology

- The reduced requirements for spinning reserve frees up low cost generation units to serve the energy needs of the region. This component is valued using production cost analysis.

Those Spin-related improvements provide annual benefits of $76 and $81 million

5 Spinning Reserves

Assumptions	
Pre-ASM Average Spinning Reserve Requirement[1]	1,193.0 MW
Post-ASM Average Spinning Reserves[2]	876.2 MW
Production Cost Savings per MW per year[3]	$240,701 – Low Case $254,588 – High Case
Wholesale Price Index – Fuel & Power[4]	2.9%
Discount Rate	9.5%

Calculation Methodology

- Calculation is based on difference between Pre-ASM and Post-ASM Spinning Reserves multiplied by the Production Cost Savings per MW per year
- Production Cost Savings per MW were adjusted each year by the Fuel & Power Wholesale Price Index while the Pre-ASM and Post-ASM Spinning Reserves difference was held constant

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[5] ($ in Mils.)	$76	$81	$93	$586
High Estimate ($ in Mils.)	$81	$85	$99	$619

[1]2006 Spinning Reserve Requirement of 1,193 MW based on reserve requirement of 2,652 MW multiplied by 45%
[2]Average monthly Spinning Reserves (Jan. 2009 – September 2009) per Midwest ISO Monthly Operations Report for September 2009
[3]Based on Midwest ISO production cost modeling
[4]EIA 2009 Annual Energy Outlook
[5]Midwest ISO's market footprint prior to 9/1/2009 was used for these calculations

Administrative and operating costs are expected to remain relatively flat into the future and represent a small percentage of the benefits

MISO Operating Costs[1,2] (in millions)

Cost Recovery Category	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Schedule 10	$100.6	$100.3	$105.3	$103.4	$98.5	$104.3	$107.2	$112.1	$114.8	$118.4	$120.9
Schedule 16	$18.2	$16.7	$17.2	$13.5	$12.6	$13.2	$14.6	$14.7	$14.6	$15.1	$15.4
Schedule 17	$130.8	$134.9	$137.3	$119.9	$115.2	$116.9	$119.0	$117.8	$119.8	$123.4	$126.0
Total Operating Cost	**$249.6**	**$251.9**	**$259.8**	**$236.8**	**$226.3**	**$234.4**	**$240.8**	**$244.6**	**$249.2**	**$256.9**	**$262.3**

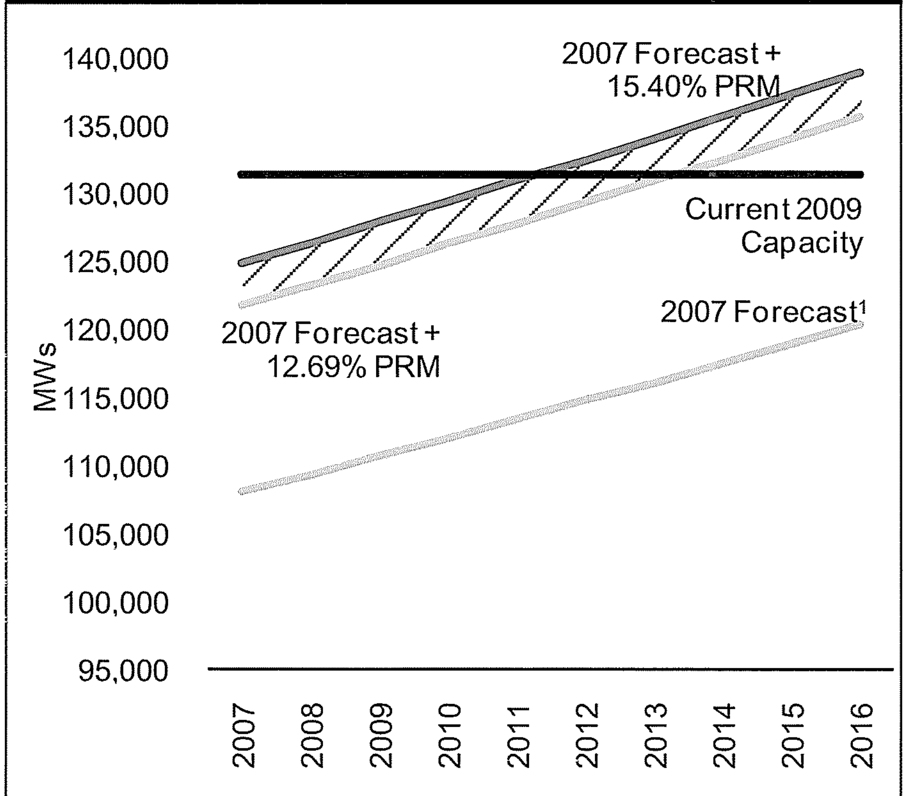
Annual cost used in the summary waterfall chart

[1]*Nominal figures*
[2]*Midwest ISO Schedule 10, 16 & 17 for 2009 through 2018; 2019 was inflated annually based on the 2018 costs at 2.1% based on Energy Information Administration Annual Energy Outlook 2009 CPI*
Note: The Midwest ISO's administrative and operating costs encompass the material costs incurred by its members. There are additional cost impacts (both increases and decreases) that are incurred, but we deem these costs to be small and not have a material impact on the overall value that Midwest ISO provides.

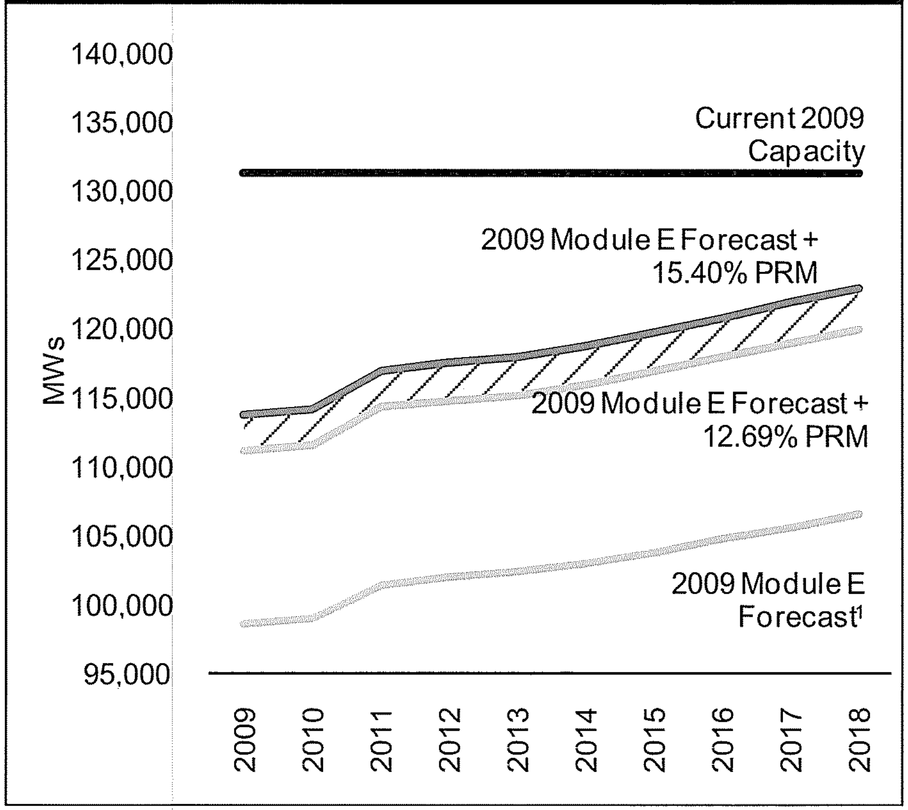
Recent economic conditions have reduced the region's load forecast and delayed the need for new capacity. However, capacity may be required if load returns sooner than forecast or retirements are accelerated due to carbon constraints

7 Footprint Diversity

Planning Reserve Margin (PRM) Requirements: 2007-2016



Planning Reserve Margin (PRM) Requirements: 2009-2018

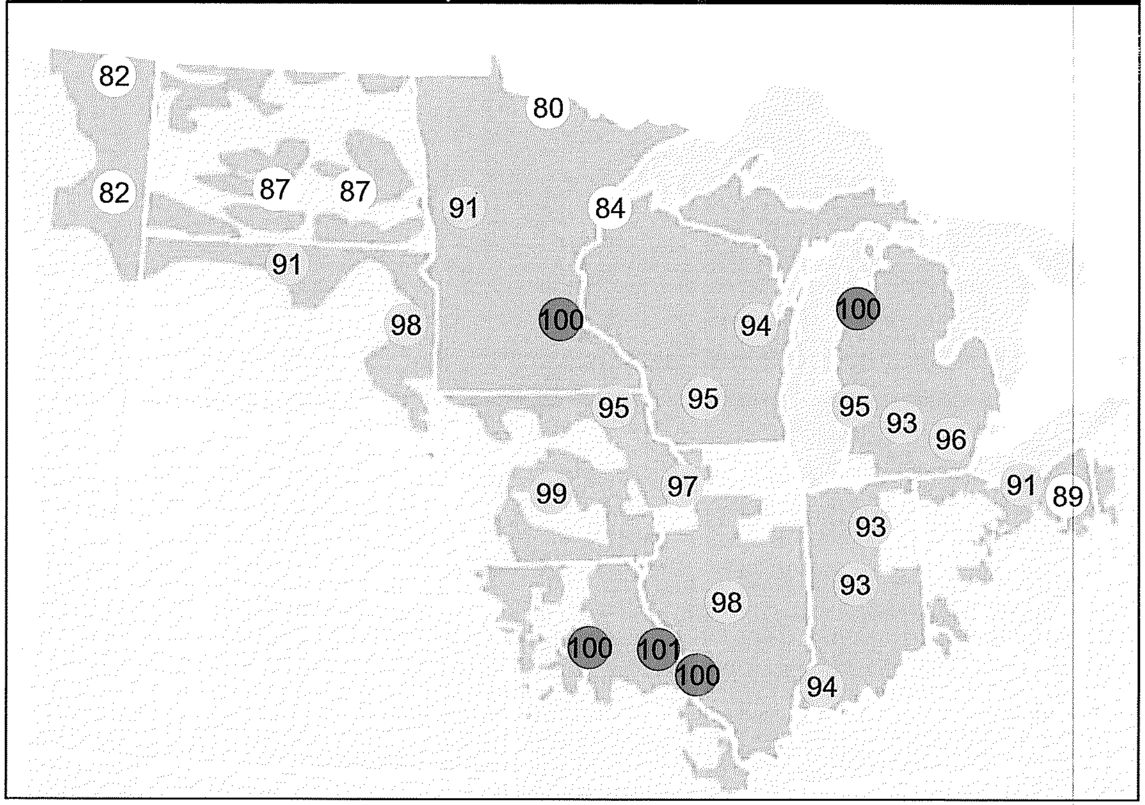


[1]*Load Forecast provided by Midwest ISO Load Serving Entities*

Midwest ISO's large footprint increases the load diversity factor allowing for a decrease in regional planning reserve margins from 15.40% to 12.69%

7 Footprint Diversity

High Temperatures on July 31, 2006
Midwest ISO Peak of 116,273 MW for 2006



Load Diversity Factor Explained

- The high temperature map illustrates that the peak for each Load Serving Entity (LSE) does not occur simultaneously
- Within Module E, individual LSEs maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely an entity's own peak, which could occur at a different time than the system peak.
- To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 2.35% diversity factor

MidwestISO
Energizing the Heartland

7 Footprint Diversity

This planning reserve margin decrease results in annual benefits of between $217 and $272 million

Assumptions	
2009 Peak Demand Forecast[1]	98,559.0 MW
Peak Demand Growth Rate – 2010 to 2018	Based on 10-Year Non-Coincident Forecast Provided by LBAs
Planning Reserve Margin, Without ISO	15.40%
Planning Reserve Margin, With ISO	12.69%
Capital Cost/MW[2]	$800,000 - Low Estimate $1,000,000 – High Estimate
Discount Rate	9.50%

Calculation Methodology

- The shift from localized use of the electrical system to regional use allows more efficient and effective use of the generation assets and allows a reduction in the planning reserve margins for the region
- Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only

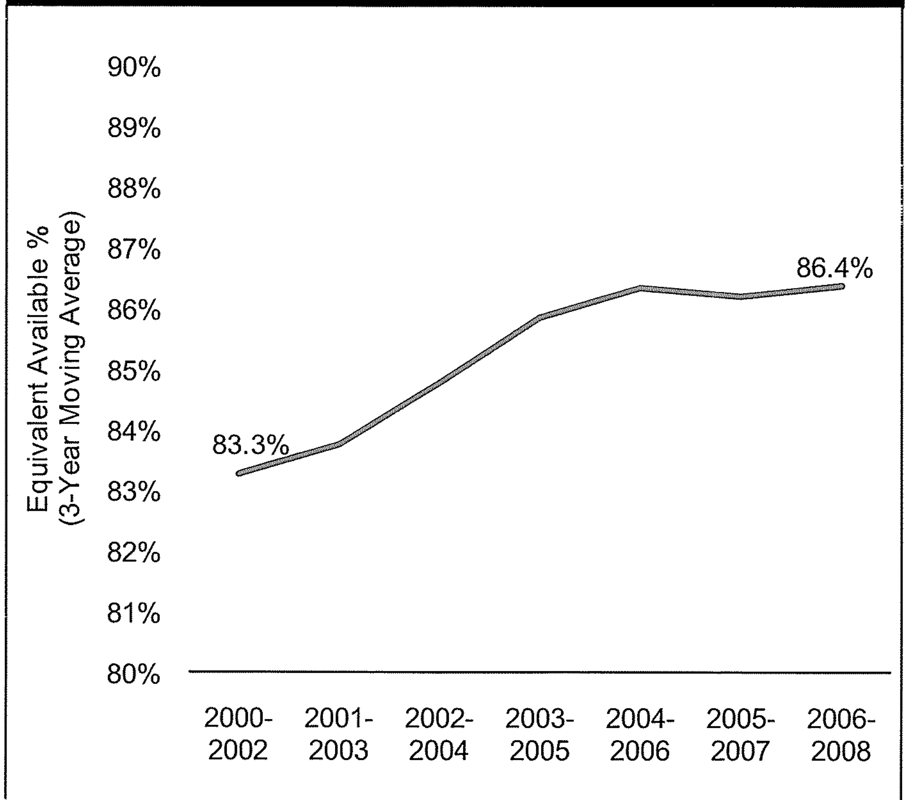
	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[3] ($ in Mils.)	$217	$222	$231	$1,546
High Estimate ($ in Mils.)	$272	$277	$288	$1,932

[1]Midwest ISO 2009 Summer Assessment
[2]Capital Cost/MW capacity is based on combustion turbine generation
[3]Midwest ISO's market footprint prior to 9/1/2009 was used for these calculations

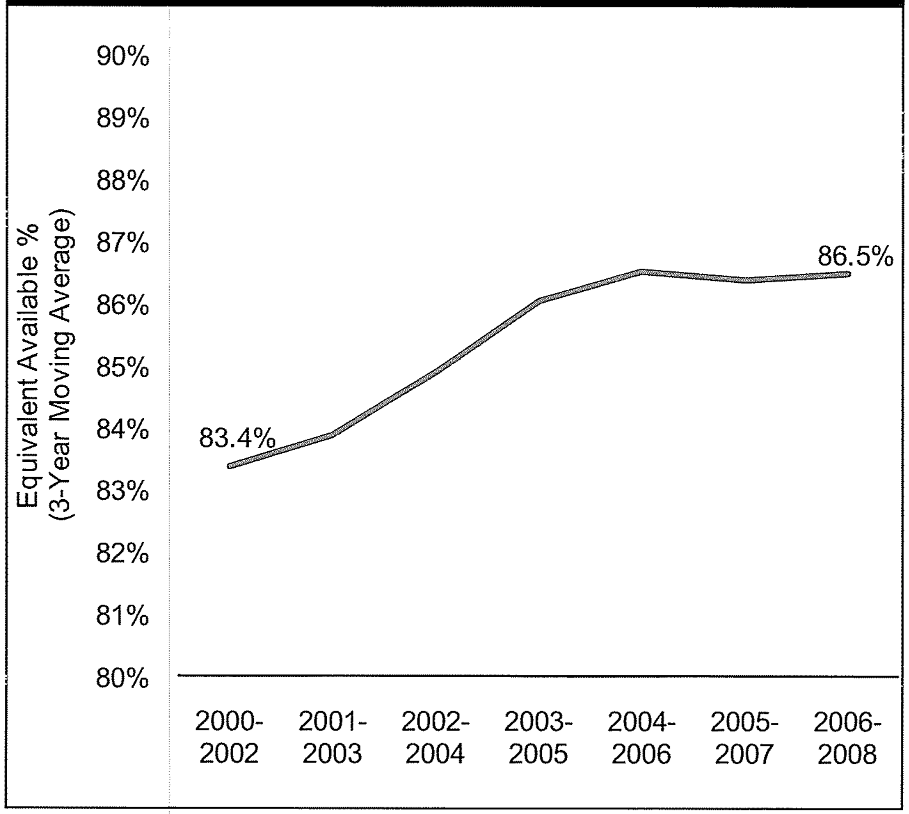
The Midwest ISO's wholesale power market has resulted in power plant availability improvements of 3.1% delaying the need to construct new capacity

8 Generator Availability Improvement

Generator Availability – Baseload Units Only[1]



Generator Availability – All Units[1]



Midwest ISO Energizing the Heartland

[1]*Generator Availability Data System (GADS) – 2000 to 2008*

The delay in capacity construction provides an annual benefit for Midwest ISO at an estimated $249 to $311 million

8 Generator Availability Improvement

Assumptions	
2009 Peak Demand Forecast[1]	98,559.0 MW
Peak Demand Growth Rate – 2010 to 2018	Based on 10-Year Non-Coincident Forecast Provided by LBAs
Midwest ISO Generator Availability Improvement %	3.10%
Capital Cost/MW[2]	$800,000 - Low Estimate $1,000,000 – High Estimate
Discount Rate	9.50%

Calculation Methodology

- Competitive wholesale power markets provides generation owners incentives to achieve higher power plant availability and lower forced outages rates which reduces the need for construction of new generation capacity
- Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only

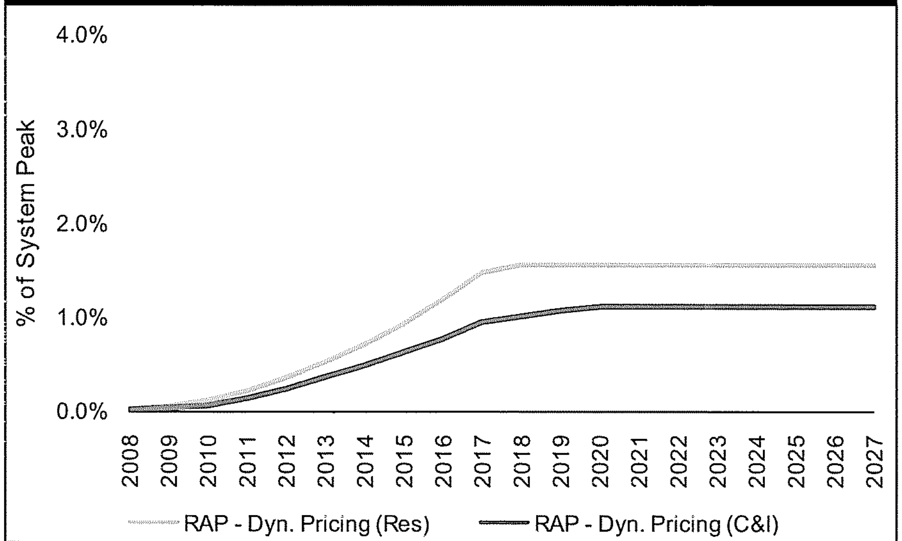
	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate[3] ($ in Mils.)	$249	$254	$264	$1,768
High Estimate ($ in Mils.)	$311	$317	$330	$2,210

[1]Midwest ISO 2009 Summer Assessment
[2]Capital Cost/MW capacity is based on combustion turbine generation
[3]Midwest ISO's reliability footprint prior to 1/1/2009 was used for these calculations

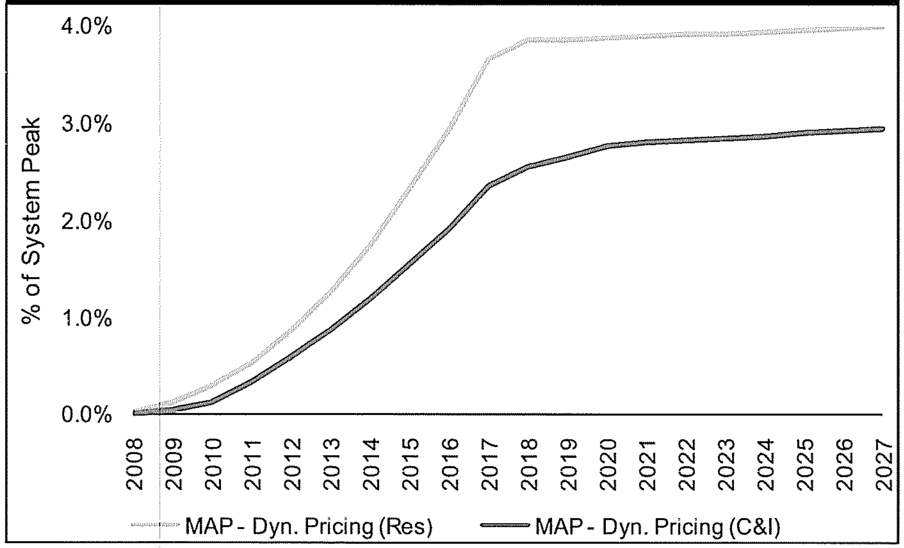
MidwestISO Energizing the Heartland

Dynamic Pricing provides customers a rate signal that varies throughout the day to reflect the higher cost of electricity during peak times than off-peak times

Dynamic Pricing Realistic Achievable Potential (RAP)[1]



Dynamic Pricing Maximum Achievable Potential (MAP)[1]



[1] *The Brattle Group, "Fostering Economic Demand Response in the Midwest ISO", 12/30/2008*

Dynamic Pricing allows additional generation investment deferral resulting in annual benefits of $4 to $7 million with significant future growth

Assumptions	
2009 Peak Demand Forecast[1]	98,559.0 MW
10-Year Dynamic Pricing Penetration Rates[2]	Realistic Potential: 0.05% to 2.55% Maximum Potential: 0.14% to 6.39%
Peak Demand Growth Rate – 2010 to 2018	Based on 10-Year Non-Coincident Forecast Provided by LBAs
Capital Cost/MW[3]	$800,000 – Low Case $1,000,000 – High Case
Discount Rate	9.50%

Calculation Methodology

- Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only

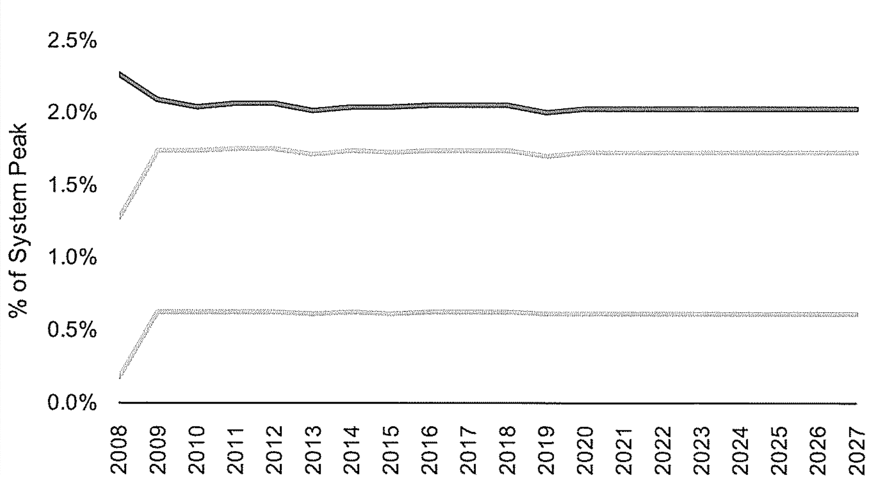
	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate – Realistic Potential[5] ($ in Mils.)	$4	$33	$164	$546
High Estimate – Maximum Potential[4] ($ in Mils.)	$7	$51	$256	$853

[1]*Midwest ISO 2009 Summer Assessment*
[2]*The Brattle Group, "Fostering Economic Demand Response in the Midwest ISO", 12/30/2008*
[3]*Capital Cost/MW capacity is based on combustion turbine generation*
[4]*High estimate is derived by multiplying the 10-Year Maximum Potential Dynamic Pricing Penetration Rates of 0.14% to 6.39% by 50%*
[5]*Midwest ISO's market footprint prior to 1/1/2009 was used for these calculations*

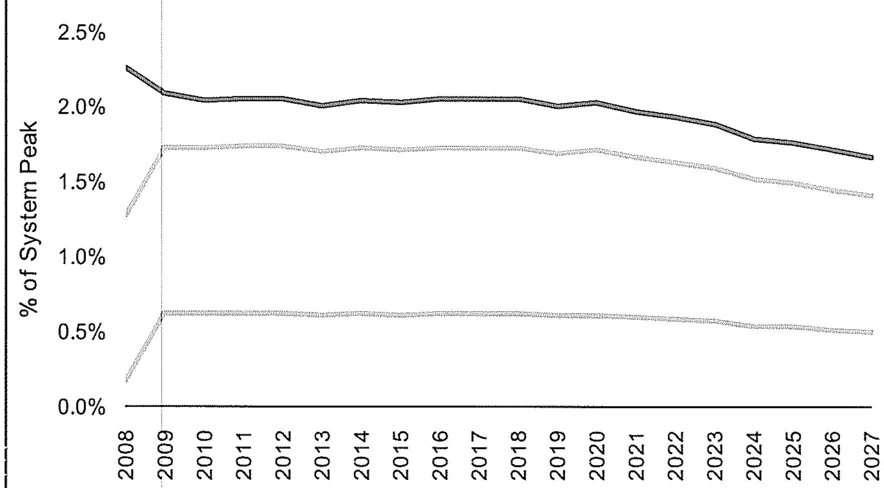
Direct Load Control (DLC) provides LSEs ability to curtail specific end-use of customers while Interruptibles (Int) provides ability to curtail preset amount of load

10 Direct Load Control - Interruptibles

DLC-Int Realistic Achievable Potential (RAP)[1]



DLC-Int Maximum Achievable Potential (MAP)[1]



Midwest ISO
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[1] *The Brattle Group, "Fostering Economic Demand Response in the Midwest ISO", 12/30/2008*

Direct Load Control and Interruptibles enable LSEs to defer generation investment by lowering demand resulting in annual benefits of $58 to $72 million

10 Direct Load Control - Interruptibles

Assumptions	
2009 Peak Demand Forecast[1]	98,559.0 MW
10-Year Direct Load Control/Interruptibles Penetration Rates[2]	Realistic Potential: 0.72% to 0.69% Maximum Potential: 0.72% to 0.69%
Peak Demand Growth Rate – 2010 to 2018	Based on 10-Year Non-Coincident Forecast Provided by LBAs
Capital Cost/MW[3]	$800,000 – Low Case $1,000,000 – High Case
Discount Rate	9.50%

Calculation Methodology

- Avoided cost benefit annualized using an estimated revenue requirement for the capital cost only

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate – Realistic Potential[4] ($ in Mils.)	$58	$56	$58	$391
High Estimate – Maximum Potential ($ in Mils.)	$72	$70	$73	$488

[1]Midwest ISO 2009 Summer Assessment
[2]The Brattle Group, "Fostering Economic Demand Response in the Midwest ISO", 12/30/2008
[3]Capital Cost/MW capacity is based on combined cycle gas fired generation
[4]Midwest ISO's market footprint prior to 1/1/2009 was used for these calculations

Midwest ISO has demonstrated significant qualitative benefits that wholesale market participants derive from the existence and operation of the Midwest ISO

Price Transparency

Description

- Improved price transparency enables market forces by signaling them to supply energy when it is scarce, invest in transmission to free constraints, and invest in generation to meet long-term and short-term needs. The Midwest ISO's market provides this information at a level of granularity and locational specificity that no traditional decentralized bilateral energy market can match.

Planning Coordination

Description

- In a traditional transmission planning process, a transmission owner (TO) focuses on relieving transmission constraints and reliability issues in the transmission system they own. In the Midwest ISO's planning process this "bottoms-up" approach is coordinated between all TOs in our footprint and combined with a "top-down" approach looking at not just the regional footprint but also looking into surrounding regions and determining what transmission investments will allow for the lowest reliably delivered cost of energy for the footprint.
- The Midwest ISO Transmission Expansion Plan 2008 recommended projects totaling $4.2 billion and proposed projects totaling $1.6 billion. Together these projects will provide for more than $1 billion in annual benefits.

Midwest ISO has demonstrated significant qualitative benefits that wholesale market participants derive from the existence and operation of the Midwest ISO (cont'd)

Regulatory Compliance

Description

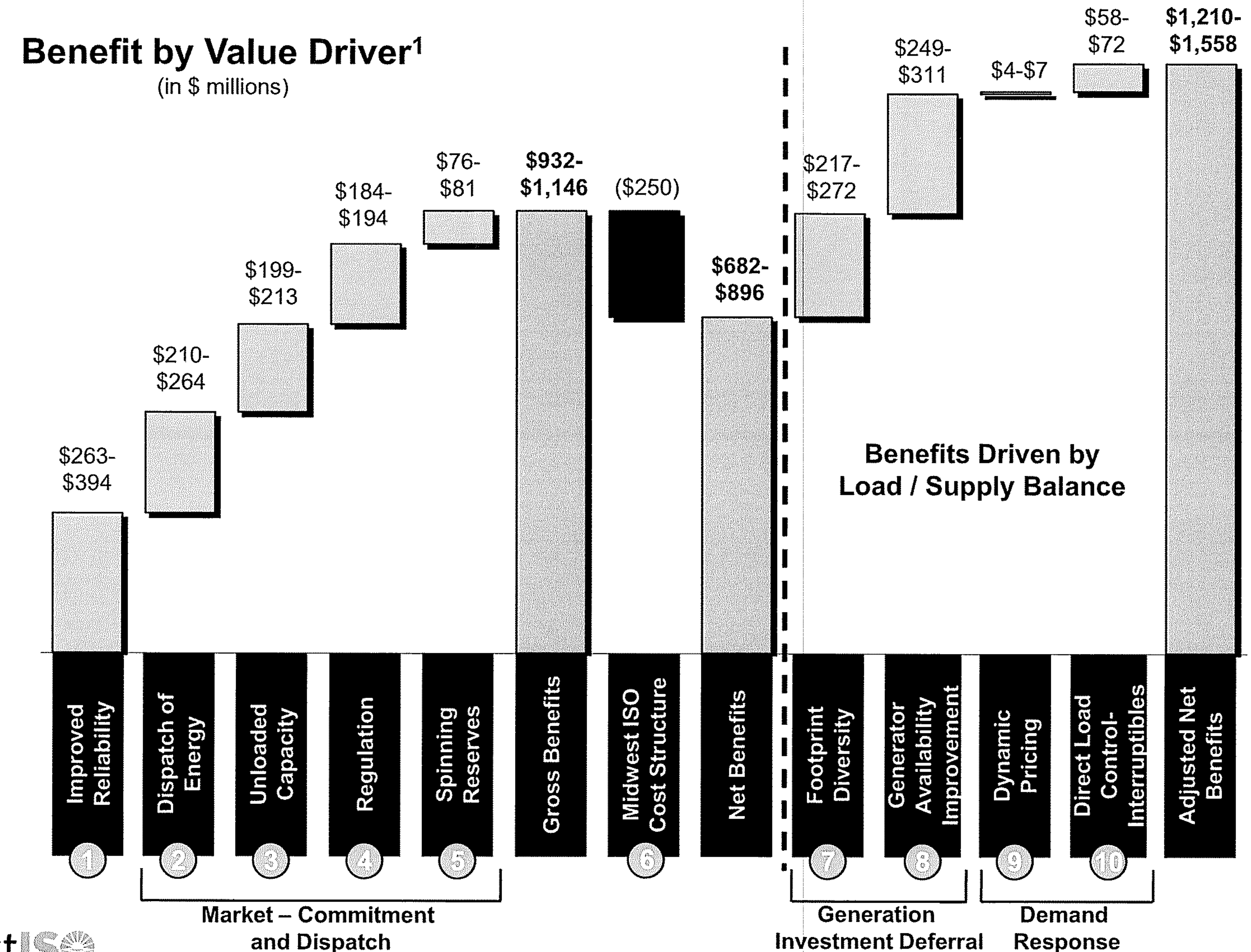
- The Midwest ISO adds value by performing several compliance activities on behalf of its members including:
  - Holding monthly conference calls with members to jointly develop higher quality input into the standards process
  - Engaging in several NERC standard drafting teams
  - Performing tasks previously performed by each individual Balancing Authority under the Balancing Authority agreement
  - Providing planning coordination services for the resource adequacy process
  - Providing training services that help our members meet compliance obligations and assist operators in maintaining their certification

Wholesale Platform for Integrating Renewables

Description

- The Midwest ISO adds the following benefits through integration of renewable resources:
  - Providing one-stop shopping for interconnection to the system
  - Enabling access to a spot market for energy
  - Coordinating dispatch over a large balancing authority area provides a greater ability to accommodate the output variations of intermittent resources thus enabling a greater amount of renewable resources to operate in the region than would otherwise be possible

The Midwest ISO 2009 Value Proposition



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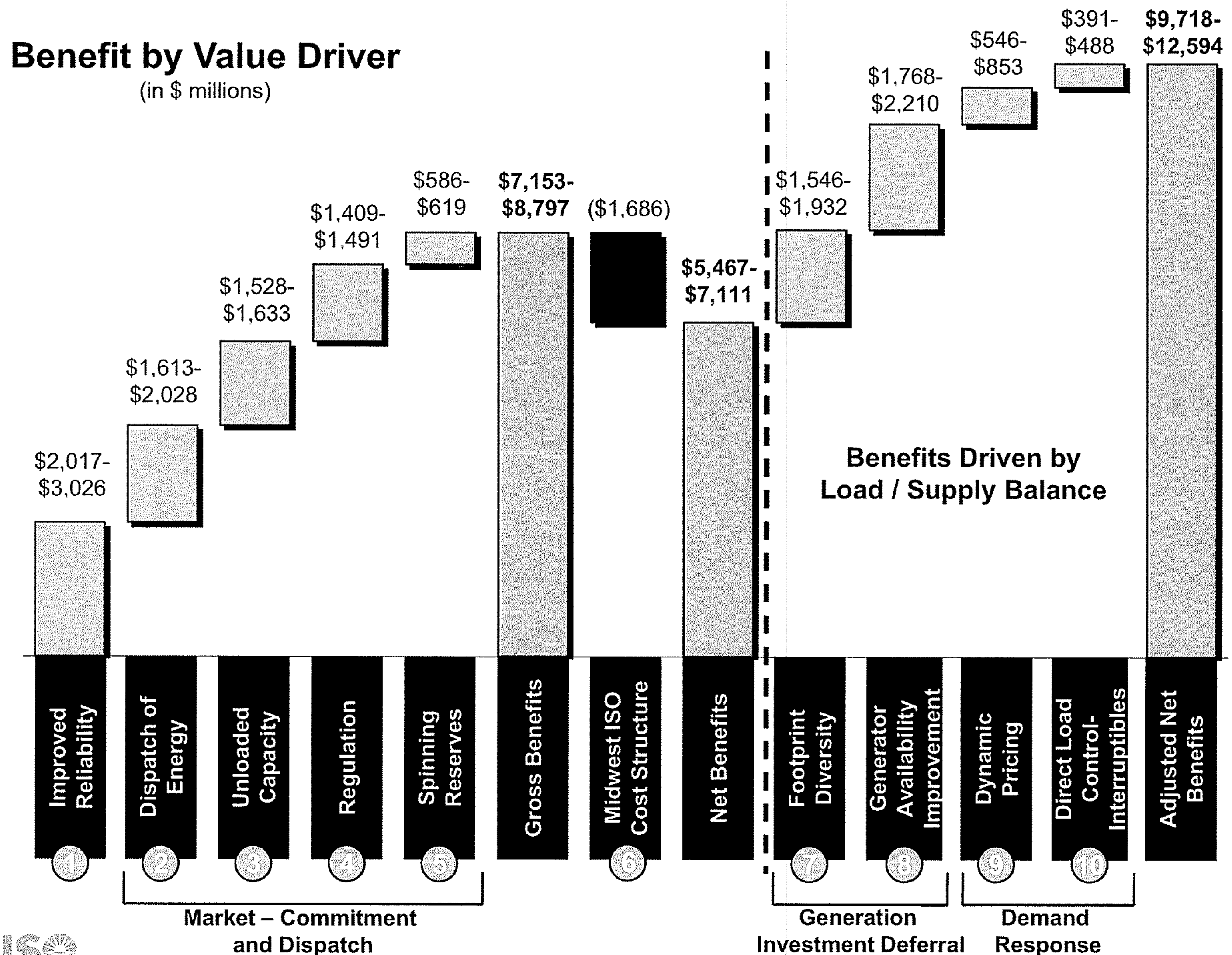
[1]*Figures shown reflect annual benefits and costs that can be expected in 2009*

Attachment 11 of Item KIUC MISO 1-2
Page 30 of 31

The Midwest ISO 2009 Value Proposition – 10 Year NPV



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ATTACHMENT 12

Midwest ISO
Energizing the Heartland

2009 Value Proposition
MISO Unloaded Capacity Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$47	$50	$58	$362
High Estimate ($ in Mils.)	$52	$55	$64	$400

Assumptions	
Annual Inflation Rate	2.90% [1]
Discount Rate	9.50% [2]

Calculation Detail ($ in Mils.)

	A	B	C	D	E		
Year	Pre-ASM Operating Unloaded Capacity (MW) 12/2006 to 11/2007 [3]	Post-ASM Operating Unloaded Capacity (MW) 1/2009 - 9/2009 [4]	Unloaded Capacity Reduction (MW) A - B	Production Costs Savings per MW Low Estimate [5]	Production Costs Savings per MW High Estimate [5]	Benefit Low Estimate C X D	Benefit High Estimate C X E
2009	692	338	354	$0.133066	$0.147073	$47	$52
2010	692	338	354	$0.136925	$0.151338	$48	$54
2011	692	338	354	$0.140896	$0.155727	$50	$55
2012	692	338	354	$0.144982	$0.160243	$51	$57
2013	692	338	354	$0.149186	$0.164890	$53	$58
2014	692	338	354	$0.153513	$0.169672	$54	$60
2015	692	338	354	$0.157964	$0.174592	$56	$62
2016	692	338	354	$0.162545	$0.179655	$58	$64
2017	692	338	354	$0.167259	$0.184865	$59	$65
2018	692	338	354	$0.172110	$0.190227	$61	$67

The MISO Unloaded Capacity benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

Midwest ISO
Energizing the Heartland

2009 Value Proposition
MISO Unloaded Capacity Benefit

Sources

[1] 2.9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators. Annual Growth 2007-2030 (percent). Wholesale Price Index (1982-1.00). Fuel and Power.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] Pre-ASM Midwest ISO Unloaded Capacity (MW)

Nov-07	600	Midwest ISO Monthly Operations Report, November 2008
Oct-07	700	Midwest ISO Monthly Operations Report, October 2008
Sep-07	300	Midwest ISO Monthly Operations Report, September 2008
Aug-07	300	Midwest ISO Monthly Operations Report, August 2008
Jul-07	600	Midwest ISO Monthly Operations Report, July 2008
Jun-07	1000	Midwest ISO Monthly Operations Report, June 2008
May-07	300	Midwest ISO Monthly Operations Report, May 2008
Apr-07	500	Midwest ISO Monthly Operations Report, April 2008
Mar-07	500	Midwest ISO Monthly Operations Report, March 2008
Feb-07	700	Midwest ISO Monthly Operations Report, February 2008
Jan-07	1100	Midwest ISO Monthly Operations Report, January 2008
Dec-06	1700	Midwest ISO Monthly Operations Report, December 2007
Pre-ASM Average	**692**	

[4] Post-ASM Midwest ISO Operating Unloaded Capacity (MW) from Midwest ISO Monthly Operations Report, September 2009

Jan-09	600
Feb-09	530
Mar-09	640
Apr-09	200
May-09	140
Jun-09	200
Jul-09	390
Aug-09	210
Sep-09	130
Post-ASM Average	**338**

[5] Production Cost Savings per MW

Year	Inflation Rate	Production Cost Savings per MW ($ in Mils.) - Low	Production Cost Savings per MW ($ in Mils.) - High
2008	N/A	$0.143735	$0.158865
2009	-7.4%	$0.133066	$0.147073

Note #1 - Inflation Rate from Actual PPI from Bureau of Labor Statistics based on Electric Power Generation industry. Actual PPI for 2009 is thru August 2009 only. Actual PPI thru August 2009 was assumed to be indicative of the Actual PPI for the entire 2009 year.

Note #2 - Production Cost Savings per MW based on Midwest ISO production cost modeling performed in 2008.

Note #3 - Beyond 2009, Production Cost Savings per MW was adjusted by the annual inflation rate of 2.9%.

ATTACHMENT 13

MidwestISO
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2009 Value Proposition
Regulation Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$184	$194	$224	$1,409
High Estimate ($ in Mils.)	$194	$206	$237	$1,491

Assumptions		
Annual Inflation Rate	2.90%	[1]
Discount Rate	9.50%	[2]

Calculation Detail ($ in Mils.)

	A	B	C	D	E		
Year	Pre-ASM Average Regulation (MW) 4/1/2008-12/31/2008 [3]	Post-ASM Average Regulation (MW) 1/1/2009 - 9/30/2009 [4]	Regulation Reduction (MW) A - B	Production Costs Savings per MW Low Estimate [5]	Production Costs Savings per MW High Estimate [5]	Benefit Low Estimate C X D	Benefit High Estimate C X E
2009	1,188	426	762	$0.240701	$0.254588	$184	$194
2010	1,188	426	762	$0.247681	$0.261971	$189	$200
2011	1,188	426	762	$0.254864	$0.269568	$194	$206
2012	1,188	426	762	$0.262255	$0.277385	$200	$211
2013	1,188	426	762	$0.269861	$0.285429	$206	$218
2014	1,188	426	762	$0.277687	$0.293707	$212	$224
2015	1,188	426	762	$0.285739	$0.302224	$218	$230
2016	1,188	426	762	$0.294026	$0.310989	$224	$237
2017	1,188	426	762	$0.302553	$0.320008	$231	$244
2018	1,188	426	762	$0.311327	$0.329288	$237	$251

The Regulation benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member

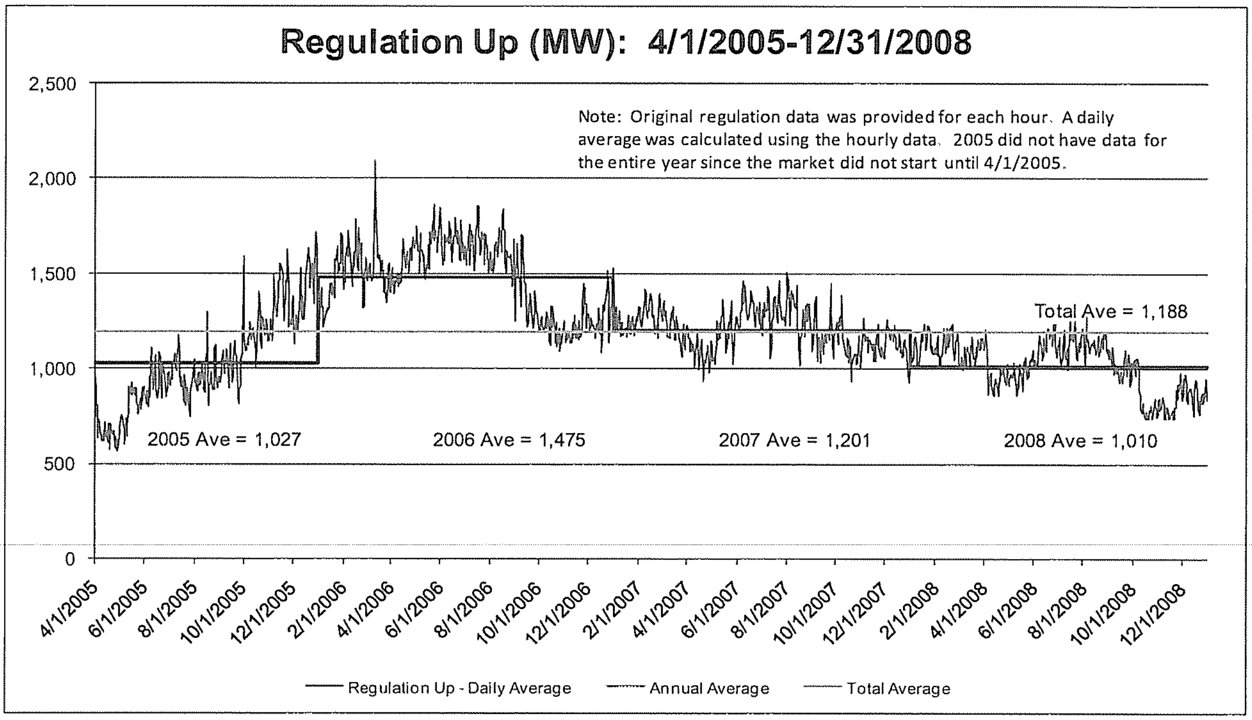
2009 Value Proposition
Regulation Benefit

Sources

[1] 2.9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators. Annual Growth 2007-2030 (percent). Wholesale Price Index (1982-1.00). Fuel and Power.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] Average Regulation Up (MW) less Average Regulation Up (MW) attributable to Louisville Gas and Electric.



[4] Post-ASM Regulation (MW) from Midwest ISO Monthly Operations Report, September 2009

Jan-09	534
Feb-09	463
Mar-09	438
Apr-09	420
May-09	392
Jun-09	398
Jul-09	396
Aug-09	394
Sep-09	395
Post-ASM Average	**426**

[5] Production Cost Savings per MW

Year	Inflation Rate	Production Cost Savings per MW ($ in Mils.) - Low	Production Cost Savings per MW ($ in Mils.) - High
2008	N/A	$0.260000	$0.275000
2009	-7.4%	$0.240701	$0.254588

Note #1 - Inflation Rate from Actual PPI from Bureau of Labor Statistics based on Electric Power Generation industry. Actual PPI for 2009 is thru August 2009 only. Actual PPI thru August 2009 was assumed to be indicative of the Actual PPI for the entire 2009 year.

Note #2 - Production Cost Savings per MW based on Midwest ISO production cost modeling performed in 2008.

Note #3 - Beyond 2009, Production Cost Savings per MW was adjusted by the annual inflation rate of 2.9%.

ATTACHMENT 14

Midwest ISO
Energizing the Heartland

2009 Value Proposition
Spinning Reserves Benefit

	Year 1	Years 1-5 (Average)	Years 6-10 (Average)	10-Year NPV
Low Estimate ($ in Mils.)	$76	$81	$93	$586
High Estimate ($ in Mils.)	$81	$85	$99	$619

Assumptions	
Annual Inflation Rate	2.90% [1]
Discount Rate	9.50% [2]

Calculation Detail ($ in Mils.)

	A	B	C	D	E		
Year	Pre-ASM Average Spinning Reserves (MW) 4/1/2008-12/31/2008 [3]	Post-ASM Average Spinning Reserves (MW) 1/1/2009 - 9/1/2009 [4]	Spinning Reserves Reduction (MW) A - B	Production Costs Savings per MW Low Estimate [5]	Production Costs Savings per MW High Estimate [5]	Benefit Low Estimate C X D	Benefit High Estimate C X E
2009	1,193	876	317	$0.240701	$0.254588	$76	$81
2010	1,193	876	317	$0.247681	$0.261971	$78	$83
2011	1,193	876	317	$0.254864	$0.269568	$81	$85
2012	1,193	876	317	$0.262255	$0.277385	$83	$88
2013	1,193	876	317	$0.269861	$0.285429	$85	$90
2014	1,193	876	317	$0.277687	$0.293707	$88	$93
2015	1,193	876	317	$0.285739	$0.302224	$91	$96
2016	1,193	876	317	$0.294026	$0.310989	$93	$99
2017	1,193	876	317	$0.302553	$0.320008	$96	$101
2018	1,193	876	317	$0.311327	$0.329288	$99	$104

The Spinning Reserves benefit is a quantification of value for the entire Midwest ISO footprint and does not calculate the value of an individual state or member.

MidwestISO
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2009 Value Proposition
Spinning Reserves Benefit

Sources

[1] 2.9% - EIA 2009 Annual Energy Outlook. Page 39, Table A20. Macroeconomic Indicators. Annual Growth 2007-2030 (percent). Wholesale Price Index (1982-1.00). Fuel and Power.

[2] Discount Rate based on an indicative weighted average cost of capital for major utility companies in the Midwest.

[3] 1,193 MW - Pre-ASM Spinning Reserves (based on reserve requirement of 2,652 MW multiplied by 45%).

[4] Post-ASM Spinning Reserves (MW) from Midwest ISO Monthly Operations Report, September 2009.

Jan-09	938.6
Feb-09	907.4
Mar-09	887.6
Apr-09	857.3
May-09	828.8
Jun-09	849.0
Jul-09	852.8
Aug-09	862.2
Sep-09	902.5
Post-ASM Average	**876.2**

[5] Production Cost Savings per MW

Year	Inflation Rate	Production Cost Savings per MW ($ in Mils.) - Low	Production Cost Savings per MW ($ in Mils.) - High
2008	N/A	$0.260000	$0.275000
2009	-7.4%	$0.240701	$0.254588

Note #1 - Inflation Rate from Actual PPI from Bureau of Labor Statistics based on Electric Power Generation industry. Actual PPI for 2009 is thru August 2009 only. Actual PPI thru August 2009 was assumed to be indicative of the Actual PPI for the entire 2009 year.

Note #2 - Production Cost Savings per MW based on Midwest ISO production cost modeling performed in 2008.

Note #3 - Beyond 2009, Production Cost Savings per MW was adjusted by the annual inflation rate of 2.9%.

ATTACHMENT 15

Company Facts

Midwest ISO is an independent, nonprofit organization that supports the constant availability of electricity in 13 U.S. states and the Canadian province of Manitoba.

This responsibility is carried out by ensuring the reliable operation of interconnected high voltage power lines that enable the transmission of more than 100,000 MW of energy in the Midwest, by administering one of the world's largest energy markets, and by looking ahead to identify improvements to the wholesale bulk electric infrastructure that will best meet the growing demand for power in an efficient and effective manner.

Midwest ISO was approved as the nation's first regional transmission organization (RTO) in 2001. The organization is headquartered in Carmel, Indiana with operations centers in Carmel and St. Paul, Minnesota.

Customer Service
Effective Communication
Operational Excellence

Midwest ISO
Energizing the Heartland

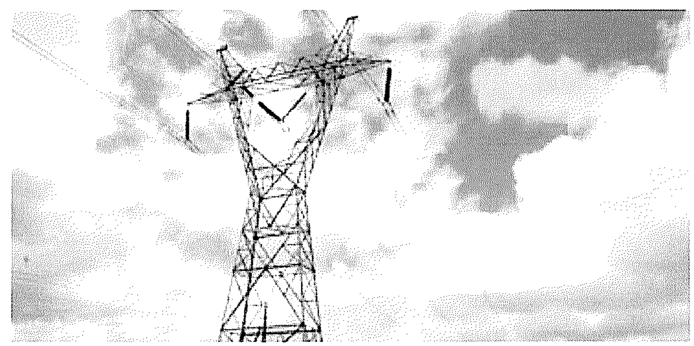
Carmel Office
P.O. Box 4202
Carmel, IN 46082-4202
Phone: (317) 249-5400
Fax: (317) 249-5910

St. Paul Office
1125 Energy Park Drive
St. Paul, MN 55108
Phone: (651) 632-8400
Fax: (651) 632-8417

www.midwestmarket.org

Bringing Value to the Heartland

2009 Value Proposition



Quantitative Benefits

1. **Improved Reliability - $263 to $394 million in annual benefits** The Midwest ISO's broad regional view and state-of-the-art reliability tool set enable improved reliability for the region as measured by transmission system availability.

2. **Dispatch of Energy - $210 to $264 million** The Midwest ISO's real-time and day-ahead energy markets use security constrained unit commitment and centralized economic dispatch to optimize the use of all resources within the region based on bids and offers by market participants.

3. **Unloaded Capacity - $199 to $213 million** With the start of the Ancillary Services Market and the functional consolidation of the region's Balancing Authorities, responsibility to respond to operating issues was consolidated in the Midwest ISO, eliminating the need for multiple Balancing Authorities to hold unloaded capacity.

4. **Regulation - $184 to $194 million** With the start of the Midwest ISO Regulation Market, the amount of regulation reserves required within the Midwest ISO's footprint has dropped significantly. This is the outcome of the region moving to a centralized common footprint regulation target rather than a number of non-coordinated regulation targets within the footprint.

5. **Spinning Reserves - $76 to $81 million** Starting with the formation of the Contingency Reserve Sharing Group and continuing with the implementation of the Spinning Reserves Market, the total spinning reserve requirement has been reduced, freeing low-cost capacity to meet energy requirements.

6. **Midwest ISO Cost Structure - $250 million in annual costs** Administrative and operating costs are expected to remain relatively flat into the future. The near term annual cost is $250 million.

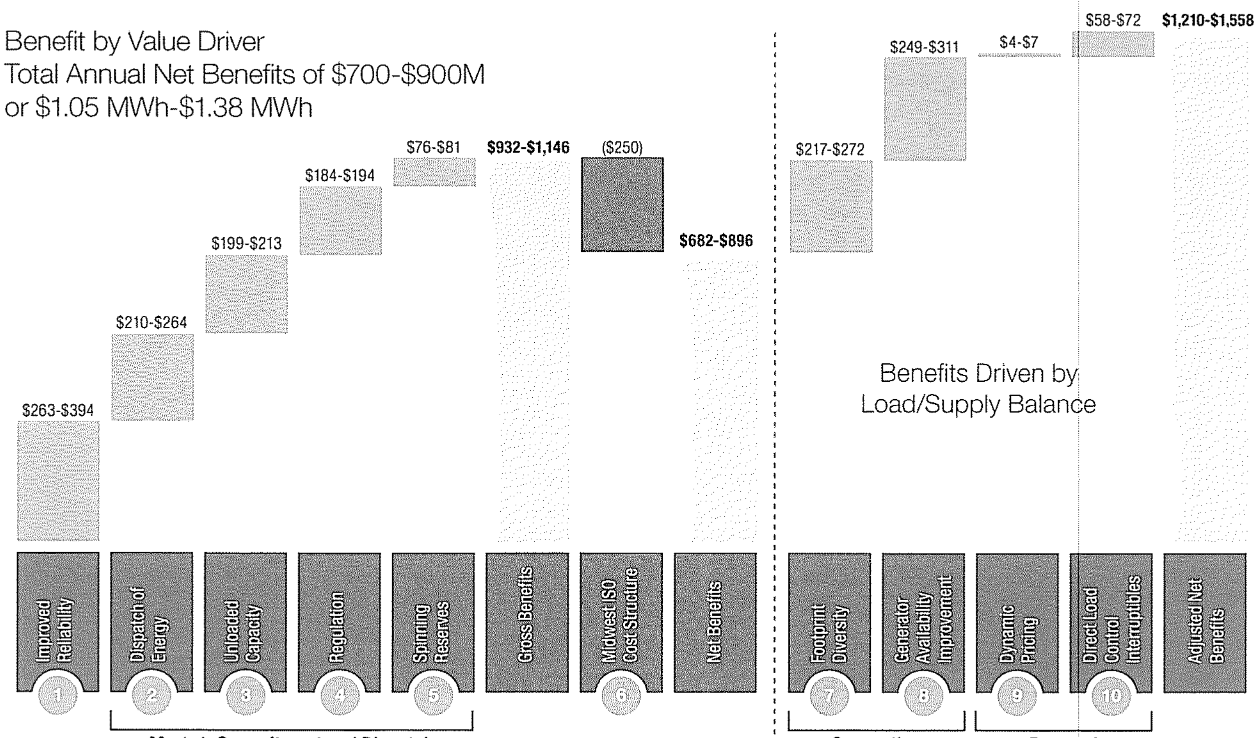
7. **Footprint Diversity - $217 to $272 million** Midwest ISO's large footprint increases the load diversity factor allowing for a decrease in regional planning reserve margins from 15.40% to 12.69%. This decrease delays the need to construct new capacity.

8. **Generator Availability Improvement - $249 to $311 million** The Midwest ISO's wholesale power market has resulted in power plant availability improvements of 3.1%, delaying the need to construct new capacity.

9. **Dynamic Pricing - $4 to $7 million** The Midwest ISO enables dynamic pricing which provides customers with a rate signal that reflects the higher cost of providing electricity during peak times than off-peak times. Dynamic pricing allows additional generation investment deferral.

10. **Direct Load Control and Interruptible Contracts - $58 to $72 million** The Midwest ISO enables direct load control and interruptible contracts which provide load serving entities the ability to curtail load. This allows the load serving entities to defer generation investment by lowering demand.

Benefit by Value Driver
Total Annual Net Benefits of $700-$900M
or $1.05 MWh-$1.38 MWh



Attachment 15 of Item KIUC MISO 1-2
Page 2 of 2

Qualitative Benefits

In addition to the quantitative benefits the Midwest ISO has demonstrated as part of its Value Proposition, there are also significant qualitative benefits that wholesale market participants derive from the existence and operation of the Midwest ISO, including:

1. Price transparency
2. Planning coordination
3. Regulatory compliance
4. Wholesale platform for integrating renewables

MidwestISO
Energizing the Heartland

Item KIUC MISO 1-3) ***Please reference lines 3 – 9 of page 15 of your direct testimony. Please explain how MISO operations that employ SCUC and SCED analysis procedures reside within or under your authority and purview?***

Response) The unit commitment process involving SCUC and the economic dispatch using SCED are not my responsibility. The underlying capabilities of the transmission system, outage scheduling, and planning criteria that make SCUC and SCED possible, are my responsibility. There is, by necessity, close coordination between my group's function and that of real-time operations, and market operations requiring significant knowledge transfer to enable SCUC and SCED to function as designed. In addition, as indicated in my testimony, I have career experience in control room operations, and I am familiar with unit dispatch and unit commitment requirements.

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-4) ***Please reference lines 1 – 4 of page 16 of your direct testimony. Have you, your staff, or MISO conducted studies which demonstrate that congestion costs experienced historically by Big Rivers will be above congestion costs (for Big Rivers) following its potential participation in MISO? If the answer is Yes, please provide Documents and Studies, including workpapers, where this result is obtained. For such statement by you to be accurate, would it not require a backcast study of the relevant historical period, where Big Rivers' operations are simulated under the condition that Big Rivers is participating in MISO? If the answer is No, please explain how such a result would otherwise be obtained.***

Response) We have not conducted a study to demonstrate that congestion costs experienced historically by Big Rivers will be above congestion costs (for Big Rivers) following its potential participation in MISO. But other studies performed by MISO and other entities show that congestion management through centralized Security Constrained Unit Commitment and Economic Dispatch can lower the production cost compared to the traditional TLR approach. This benefit comes from two aspects: re-dispatch is more efficient than the TLR, and the transmission system can be more efficiently utilized (a higher transmission line rating can be reached in an energy market than with traditional TLR).

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-5) ***Please state whether the FERC or any state regulatory commission has ever accepted or adopted the methodology presented on pages 22-23 of your direct testimony: Namely, that a proportion of MISO's Value Proposition, where the ratio of the entity's peak demand to MISO system peak demand is used to determine likely net benefits that a prospective MISO participant may realize if it joined MISO. If your response is Yes, please identify the proceeding, the regulatory authority that conducted such proceeding, the docket type and number of the proceeding, and the date of the resulting regulatory Order. Also provide a copy of the respective Order.***

Response) No. The method used to estimate Big Rivers' potential benefits, using a ratio of the total Value Proposition benefits, has not been submitted for adoption or acceptance in any state or federal proceeding. However, in 2007, witness Richard Doying submitted rebuttal testimony in Missouri PSC Case No. EO-2008-0046 regarding the share of projected Value Proposition indicative benefits that could be gained by Aquila joining the Midwest ISO. That testimony used the ratio of peak demand approach. The testimony and a copy of the commission order (issued October 9, 2008) are included with this response.

Witness) **<u>Clair J. Moeller</u>**

ATTACHMENT 1

Exhibit No.:	_____
Issue:	Range of benefits for Aquila as a member participant in Midwest ISO
Witness:	Richard Doying
Sponsoring Party:	Midwest Independent Transmission System Operator, Inc.
Case No.:	Case No. EO-2008-0046

Case No. EO-2008-0046

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

REBUTTAL TESTIMONY

OF

RICHARD DOYING

Carmel, Indiana
November, 2007

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	)	Case No. EO-2008-0046

AFFIDAVIT OF RICHARD DOYING

STATE OF INDIANA)
) **ss.**
COUNTY OF HAMILTON)

Richard Doying, being first duly sworn on his oath, states:

1. My name is Richard Doying. I am presently Vice President of Market Operations for Midwest Independent Transmission System Operator, Inc., intervener in the above-referenced matter.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my personal knowledge, information and belief.

Richard Doying

Subscribed and sworn before me this 29th day of November, 2007.

Dorothy M. Shute
Notary Public for Hendricks County, Indiana
My Commission expires: May 8, 2009

DOROTHY M. SHUTE
NOTARY PUBLIC, State of Indiana
My County of Residence Hendricks
My Commission Expires: May 8, 2009

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard Doying. My business address is 701 City Center Drive, Carmel, Indiana, 46032.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") as the Vice President - Market Operations.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received my Bachelor of Arts in Geography from the University of California, Los Angeles in 1991 and my Master of Arts of Public Affairs in Policy Analysis, Energy and Environmental Policy from the University of Minnesota in 1993. Starting in 1993, I was an Associate with ICF Resources Incorporated, becoming a Senior Associate in 1995. In 1997, I was made the Project Manager for ICF Resources Incorporated. In 1997, I became a manager in the Market Assessment division of PG&E National Energy Group, where I was also made Director of the same division in 1999. In 2001, I was named the Director of the Strategy and New Initiatives division of the PG&E National Energy Group. In December 2003, I became the Director of Market Development and Analysis with the Midwest ISO, and in September 2006, I became the Vice President of Market Operations.

Q. WHAT ARE YOUR JOB RESPONSIBILITIES AT THE MIDWEST ISO?

A. As Vice President of Market Operations, I am responsible for the operations of the Day-Ahead Energy Market, Financial Transmission Rights Market, Real-Time Energy Market Pricing, Tariff and Market Settlements, Customer Management, and Market

Development and Analysis. I also manage the Midwest ISO's stakeholder efforts related to market issues.

Q. HAVE YOU SPONSORED ANY OTHER TESTIMONY BEFORE REGULATORY COMMISSIONS?

A. I have testified before a number of regulatory commissions and state legislative bodies. In addition, I have also submitted written testimony before the Federal Energy Regulatory Commission in Docket No. ER04-691-000 concerning the Midwest ISO's Open Access Transmission and Energy Markets Tariff ("EMT"), which provides for the implementation of the Midwest ISO's Centralized Security Constrained Economic Dispatch supported by Day-Ahead and Real-Time Energy Markets and Congestion Management Provisions based on Locational Marginal Pricing and Financial Transmission Rights within the Midwest ISO Region.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The limited testimony of Aquila witness Mr. Dennis Odell presents a necessary but incomplete picture of the benefits available to Aquila from full participation in the Midwest ISO. The production cost study conducted by CRA International ("Aquila Study") is not designed to and therefore does not take into account the full range of benefits that would be available to Aquila from joining the Midwest ISO. Accordingly, the purpose of my testimony is to provide the Public Service Commission of the State of Missouri ("Commission") a more complete picture and record on all benefits for an entity such as Aquila becoming a transmission-owning member and fully participating in the Midwest ISO. In particular, I will discuss the broader value proposition that comes from full participation in the Midwest ISO. The details of these benefits will be discussed in Part III of this testimony.

Q. DO YOU ADDRESS THE SUBSTANCE OF THE AQUILA STUDY?

A. No. I do not. Witness Johannes Pfeifenberger does so in his testimony.

II. MIDWEST ISO OPERATIONAL BACKGROUND

Q. PLEASE DESCRIBE THE MIDWEST ISO'S OPERATIONAL CHARACTERISTICS.

A. The Midwest ISO's operational area or "footprint" consists of 15 states and the province of Manitoba, Canada. This area covers 920,000 square miles of territory, and 93,600 miles of transmission lines. The Midwest ISO performs its Energy Markets Tariff and related responsibilities over this broad region through control rooms located in Carmel, Indiana, and Saint Paul, Minnesota.

The Federal Energy Regulatory Commission, or "FERC," approved the establishment of the Midwest ISO as an "ISO" – *i.e.*, an Independent System Operator – in 1998 in the mid-western part of the United States. Then in 2001, FERC ruled that our company also met the requirements for being an "RTO" – *i.e.*, a Regional Transmission Organization. Broadly speaking, ISOs and RTOs are independent entities that have functional control over the operation of transmission facilities of multiple transmission owners under a common tariff.

An ISO administers a common tariff that applies to all transmission services provided on the transmission facilities placed under the ISO's control. [FERC developed a template for such a common tariff – called an "Open Access Transmission Tariff," or "OATT."] The common tariff ensures that the same set of rules applies to all transmission customers, and also avoids the "pancaking" of rates that occurs when power goes through transmission facilities governed by multiple tariffs each of which may impose separate charges and terms of service. Subsequently, to further improve the accessibility and reliability of transmission system operations, FERC also promoted system operation across broad regions by an ISO. Finally, to assure non-discriminatory pricing for transmission services, FERC required ISOs to adopt market-based approaches to congestion management and schedule imbalance services.

Q. HOW DOES THE MIDWEST ISO OPERATE AND UTILIZE THE TRANSMISSION ASSETS ONCE A UTILITY TRANSFERS FUNCTIONAL CONTROL?

A. System operations under the Midwest ISO's Open Access Transmission and Energy Markets Tariff ("Energy Markets Tariff") includes balancing of generation supply to assure demand is satisfied in a dependable and efficient manner and managing transmission congestion that arises due to physical limitations of the transmission system. These services are provided by the Midwest ISO through a coordinated competitive market for electric energy. The Midwest ISO energy market operates by matching offers to sell energy with bids to buy energy through a process that determines market clearing quantities and prices while assuring total demand ("load") is satisfied at the lowest possible cost while honoring the physical limitations of the transmission used to deliver energy from generation to load.

Q. PLEASE BRIEFLY EXPLAIN THE ENERGY MARKETS THAT THE MIDWEST ISO OPERATES.

A. The Midwest ISO's energy markets currently operate over two timeframes. First is a "Day-Ahead" market, through which market participants can pre-schedule the transactions they plan to engage in on the following operating day. Second is a

"Real-Time" market, where market participants can buy or sell energy to meet conditions during the operating day that may differ from those anticipated in the Day-Ahead market.

The Midwest ISO is currently focusing efforts to further reduce supply cost and improve reliability by seeking to consolidate certain functions currently performed by twenty-four (24) separate Balancing Authorities or Control Area Operators. To that end, the Midwest ISO is presently working to implement an Ancillary Services Markets, or "ASM," designed to facilitate the management of Operating Reserves. In addition the Midwest ISO is pursuing: 1) mechanisms to encourage more flexible demand participation, 2) further coordination of transmission planning, and 3) implementation of new mechanisms to assure longer-term adequacy of regional supply resources. These enhancements will provide additional tangible benefits in terms of lower energy cost and improved reliability throughout the Midwest ISO region.

Q. WHAT OTHER FUNCTIONS ARE PERFORMED BY THE MIDWEST ISO UNDER ITS ENERGY MARKETS TARIFF THAT MAY BE IMPORTANT WHEN CONSIDERING BENEFITS OF MIDWEST ISO PARTICIPATION?

A. Another important category of RTO membership benefits is associated with transmission expansion planning. Midwest ISO is the NERC Planning Authority for its member footprint, and performs regional planning in accordance with FERC Planning Principles delineated in Order 890. These planning principles provide mechanisms to ensure that the regional planning process is open, transparent, coordinated, includes both reliability and economic planning considerations, and includes mechanisms for equitable cost sharing of expansion costs. The Midwest ISO regional planning process integrates the local planning processes of its member companies into a coordinated regional transmission plan and identifies additional expansions. The regional plan has as its objective the provision of an efficient and reliable transmission system that delivers reliable power supply to connected load customers, expands trading opportunities, better integrates the grid, alleviates congestion, provides access to diverse energy resources, and enables state and federal energy policy objectives to be met. Regional plans are produced no less frequently than biennially, and are publicly available on the Midwest ISO web site.

Q. HAVE YOU BEEN ABLE TO QUANTIFY THE BENEFITS OF PARTICIPATION IN THE MIDWEST ISO?

A. Many of the benefits of regionally coordinated transmission system operations and planning are widely recognized within the industry. Also generally recognized is the inherent difficulty in tracking and measuring each of these recognized and accepted benefits. This is due in no small part to the fact that many of the benefits cannot be measured directly given that the benefits are relative to what would have occurred but for the RTO and its operations. There is no means to directly measure what would have occurred if the RTO did not exist. The Midwest ISO has nonetheless undertaken an effort to measure, where possible, and report on these significant RTO benefits. These efforts have recently culminated in a Midwest ISO value proposition report that focuses on the benefits that accrue to the region as a result of the Midwest ISO's operations. The benefits described in that report will be discussed below in Part III of my testimony.

III. MIDWEST ISO VALUE PROPOSITION

Q. WHY IS THE MIDWEST ISO FILING TESTIMONY IN THIS MATTER?

A. My testimony augments and supplements the testimony of Witness Pfeifenberger who is responding directly to the conclusions presented by Aquila about the Aquila Study. As noted earlier, the type of study performed by CRA for Aquila is a necessary but insufficient analysis of the benefits of RTO participation. Accordingly, I will discuss the broader value proposition that comes from full participation in the Midwest ISO. From the outset, I recognize and submit that many of the benefits I will touch upon are easy to describe but may be difficult to quantify with precision. This cannot and should not, however, be a basis to leave an incomplete record regarding the value and benefits of participation in the Midwest ISO under consideration by the Commission in the course of this important review process.

Q. CAN YOU DESCRIBE THE FULL RANGE OF BENEFITS THAT WOULD BE AVAILABLE TO AQUILA AS A MEMBER OF THE MIDWEST ISO?

A. Aquila would accrue significant direct and indirect benefits from participation as a transmission-owning member of the Midwest ISO – benefits that cannot be fully captured by production cost studies such as the Aquila Study. These benefits can be grouped under the following three general categories: (1) improved reliability; (2) improved efficiency; and (3) improved opportunities for development of generation and transmission infrastructure. I am aware that some of the benefits under the second category are or may be partially addressed by the CRA-Aquila production cost study, but there are others that may not be fully covered that I will touch upon. Due to the complexities inherent with the Aquila Study and the different, broader scope of the Midwest ISO value proposition compilation that I am presenting in my testimony, a direct comparison or analysis to determine overlap cannot and should not be made. Instead, I submit this description in order to provide a full and complete picture of all the relevant benefits of Midwest ISO membership and full participation. I therefore will discuss each of the above general three categories, in turn.

Q. CAN YOU QUANTIFY THE DISCRETE AND DIRECT BENEFITS FOR AQUILA UNDER THESE THREE GENERAL CATEGORIES OF BENEFITS?

A. While the Midwest ISO has not performed any specific studies attempting to quantify the benefits that can be attributed just to Aquila should it join the Midwest ISO, the Midwest ISO has evaluated the numerous benefits that accrue to all members and participants in its markets. These same benefits would accrue to Aquila as a transmission-owning member and full participant in the Midwest ISO. Aquila represents approximately 1.7%[1] of the load and generation within the Midwest ISO footprint. It is reasonable to assume that Aquila would realize benefits in a roughly proportionate share and I therefore utilize that load ratio share to develop the ranges of numbers presented below as an approximation of the magnitude of the potential benefits for Aquila's participation in the Midwest ISO. It should be noted that this estimate is conservative in that the total benefits would increase with the addition of Aquila as a full participating member of the Midwest ISO, thereby increasing the benefits realized by Aquila.

Q. WHAT IMPROVED RELIABILITY BENEFITS WOULD AQUILA RECEIVE FROM JOINING THE MIDWEST ISO?

A. The reliability benefits fall into three categories: (a) improved reliability as compared to stand-alone operations; (b) enhanced seams management; and (c) regulatory compliance. The first category, improved reliability relative to stand-alone operations, has been quantified. Spanning 15 states and the Canadian province of Manitoba, the Midwest ISO leverages its broad regional view to identify potential impacts of transmission or generation issues on the entire Midwest ISO power system as well as on bordering

[1] This amount was calculated using Aquila's projected 2008 peak load of 1,942 MW (as presented in the CRA-Aquila Study) versus the 2008 Midwest ISO forecast peak load of 110,869 MW.

regions. This analysis looks at more than 7,500 "what if" scenarios every five minutes to identify the quickest, most effective way to manage potential issues, while also ensuring the continued operation of the wholesale bulk electric system. A quick response requires accurate information. The Midwest ISO processes system condition information every four seconds, resulting in appropriate signals being sent to generation owners in a timely manner. Using more than 240,000 points of information, the Midwest ISO examines the state of the system every 90 seconds, allowing for greater visibility into system conditions, increased ability to quickly identify the most effective response, and better coordination of needed system maintenance. The reliability benefits resulting from the above were quantified by evaluating the reduced size, duration, cost and probability of transmission outages under regional rather than stand-alone transmission systems operations. Those benefits were estimated to be between $230 and $340 million per year.

Midwest ISO Annual Benefit: Improved Reliability[2]

Market-wide Improved Reliability Benefit	**Aquila Potential**
$230 to $340 million	$4.0 to $5.9 million

Q. WHAT IMPROVED EFFICIENCY BENEFITS WOULD AQUILA REALIZE BY JOINING THE MIDWEST ISO?

A. These benefits can likewise be separated into categories reflecting a more efficient dispatch of energy as compared to stand-alone operations, reduction in the quantity of required contingency reserves and more efficient use of generation to provide operating

[2] Figures reflect annual benefits reflected in 2007 U.S. dollars, including both current and achieved benefits and projected future benefits.

reserves. As noted above, I recognize that there is overlap with the Aquila Study for these particular items, but I present this information as additional points of reference since these benefits would specifically relate to Aquila's full participation in the Midwest ISO. The concept of the benefits of coordinated market operations is simple; the more options available to meet a need, the more competitive the pricing and the more efficient delivery of the final product can become. The Midwest ISO broad regional competitive wholesale market allows the Midwest ISO to match the most cost effective and reliable source of generation with power needs over an extensive area, consequently reducing the amount of generation supply required to serve the region's needs. The annual benefits associated with all three of the categories of efficiency-related benefits identified above have been estimated at between $450 and $600 million for the Midwest ISO region as a whole. The individual components are shown in the table below.

Midwest ISO Annual Benefit: Improved Efficiencies[3]

Market-wide Improved Efficiencies Benefit	**Aquila Potential**
Dispatch of energy: $200 to $250 million	$3.4 to $4.3 million
Contingency reserves: $135 to $145 million	$2.3 to $2.5 million
Dispatch of reserves: $115 to $205 million	$2.0 to $3.5 million

Q. WHAT IMPROVED LONG-TERM INVESTMENT PLANNING BENEFITS WOULD AQUILA REALIZE BY JOINING THE MIDWEST ISO?

[3] Figures reflect annual benefits reflected in 2007 U.S. dollars, including both current and achieved benefits and projected future benefits.

A. One of the benefits of participation in a large regional system is more efficient use of the existing infrastructure, both generation and transmission. Similar to the savings associated with pooling of contingency reserves, pooling of planning reserves over a larger region reduces the level necessary to assure reliable service in future periods. In the Midwest ISO region, this is estimated to result in annual savings of $135 to $150 million.

Midwest ISO Annual Benefit: Investment[4]

Market-wide Improved Efficiencies Benefit	Aquila Potential
Planning reserves: $135 to $150 million	$2.3 to $2.6 million

Q. WHAT IS THE ACCUMULATED TOTAL FROM THE ABOVE GENERAL CATEGORIES OF BENEFITS THAT YOU DESCRIBE?

A. The following shows the summed total of the value benefits described above:

Midwest ISO Annual Benefit by Total Value Benefit[5]

Gross Annual Market-wide Benefit[6]	Aquila Potential[7]
$805 to $1,100 million	$13.9 to $18.9 million

4 Figures reflect annual benefits reflected in 2007 U.S. dollars, including both current and achieved benefits and projected future benefits.

5 Figures reflect annual benefits reflected in 2007 U.S. dollars, including both current and achieved benefits and projected future benefits.

6 The Gross Benefits sum to slightly less than the individual components due to rounding and do not reflect the Midwest ISO operational and other cost components, which total approximately $250 million.

7 The Aquila portion, if netted with its prorated portion of Midwest ISO operational costs (see Footnote 7), would be fixed at approximately $4.3 million less regardless of where in this range it fell.

Q. IN YOUR OPINION, IS THE COMMISSION'S RECORD BASED SOLELY ON THE AQUILA STUDY COMPLETE IF IT DOES NOT INCLUDE ALL OF THESE BENEFITS?

A. No, in my view it is not. I recognize that the study presented by Aquila was not intended to address and quantify each of these benefits, but rather, as Witness Pfeifenberger notes and corrects, it was designed to capture only the production cost savings. My testimony is intended to highlight and raise for consideration the full range of benefits recognized within the industry of full participation in the Midwest ISO beyond the limited items noted in the Aquila Study and discussed by Witnesses Pfeifenberger and Aquila Witness Dennis Odell.

Q. ARE THERE ADDITIONAL QUALITATIVE BENEFITS THAT THE COMMISSION SHOULD ALSO CONSIDER IN ITS ANALYSIS FOR A COMPANY SUCH AS AQUILA JOINING THE MIDWEST ISO?

A. Yes. In addition to the benefits discussed above, there are also a significant number of more difficult to quantify benefits that participants, including Aquila, derive from the existence and operation of the Midwest ISO. Failure to include these benefits in an evaluation will therefore understate the total benefits of participation in the Midwest ISO. For example, price signals that are provided by the Midwest ISO's Day-Ahead and Real-Time Markets provide a level of transparency that simply was not available prior to its inception. This greater level of transparency:

- allows users or participants to efficiently respond to market conditions and adjust consumption levels,
- enables platforms for demand participation in the form of price-responsive demand response programs, and

- supports investment analysis for future generation and transmission infrastructure development.

Another important but more difficult to quantify benefit is associated with coordinated regional transmission planning. In an independent environment, the process of building a new generator or expanding transmission can begin with the confidence that price signals being provided are true indicators of where needs exist. This trust flows through the planning process as an independent organization analyzes proposals and determines if the recommendations are in the best interest of the region. The Midwest ISO's big picture view and knowledge of the region affords the ability to more readily identify the strengths of proposed enhancements to the high voltage transmission system. This view, coupled with the Midwest ISO's independent nature, provides a level of confidence that support for projects is done with an eye toward supporting reliability and a strong market. On the reliability side, the Midwest ISO planning process strives to implement enhancements in a manner that allows energy to flow through the system in an effective, efficient, and reliable manner. On the business side, the planning process supports efforts to access low cost supplies while also reducing congestion on the system, making it easier to transfer energy between the buyer and seller. Since the Midwest ISO began regional planning, nearly $1 billion in improvement projects have been completed. These improvements include more than 460 miles of new transmission lines and upgrading almost 2,400 miles of transmission lines.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, this concludes my testimony.

ATTACHMENT 2

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Aquila, Inc., d/b/a	)	
Aquila Networks – MPS and Aquila Networks – L&P	)	
for Authority to Transfer Operational Control of Certain	)	**Case No. EO-2008-0046**
Transmission Assets to the Midwest Independent	)	
Transmission System Operator, Inc.	)	

REPORT AND ORDER

Issue Date: October 9, 2008

Effective Date: October 19, 2008

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	)))))	**Case No. EO-2008-0046**

Table of Contents

Appearances

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For Midwest Independent Transmission System Operator, Inc.

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For Kansas City Power & Light Company.

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For Union Electric Company, d/b/a AmerenUE.

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Carl J. Lumley, Curtis, Heinz, Garrett & O'Keefe, P.C., 130 S. Bemiston, Suite 200, St. Louis, Missouri 63105.

For Dogwood Energy, LLC.

Alan I. Robbins and Debra D. Roby, Jennings Strouss & Salmon, PLC, 1700 Pennsylvania Ave. NW, Suite 500, Washington, D.C. 20006, and
B. Allen Garner, City Counselor, and **Dayla Bishop Schwartz**, Assistant City Counselor, Law Department, City of Independence, 111 East Maple Street, Independence, Missouri 64050.

Nathan Williams, Deputy General Counsel, Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102

For the Staff of the Missouri Public Service Commission.

Lewis R. Mills, Jr., Public Counsel, P. O. Box 2230, Jefferson City, Missouri 65102

For the Office of the Public Counsel and the Public.

REGULATORY LAW JUDGE: Morris L. Woodruff, Deputy Chief Regulatory Law Judge

REPORT AND ORDER

Syllabus: This order denies Aquila, Inc.'s application for authority to transfer operational control of certain transmission assets to the Midwest Independent Transmission System Operator, Inc.

FINDINGS OF FACT

The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Procedural History

On August 20, 2007, Aquila, Inc., d/b/a Aquila Networks-MPS and Aquila Networks-L&P filed an application requesting authority to transfer operational control of certain transmission assets to the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). On August 28, the Commission directed that notice of the filing of Aquila's application be sent to all parties to Aquila's last rate case. That order also established an intervention deadline of September 17.

Dogwood Energy, LLC; Kansas City Power & Light Company; Southwest Power Pool, Inc.; Union Electric Company, d/b/a AmerenUE; and Midwest ISO filed timely applications to intervene. The Commission granted their requests to intervene on September 28. Subsequently, on October 30, the City of Independence, Missouri filed an application to intervene out of time. The Commission granted that application on November 13.

The Commission established a procedural schedule that required the parties to prefile direct, rebuttal, and surrebuttal testimony. An evidentiary hearing was held on April 14 and 15, 2008. The parties filed post-hearing briefs on May 29.

Independent System Operators and Regional Transmission Organizations

1. Aquila's application seeks authority to become a full member of Midwest ISO. That corporation is both an Independent System Operator (ISO) and a Regional Transmission Organization (RTO). ISOs and RTOs are independent entities that have functional control over the operation of transmission facilities of multiple transmission owners under a common tariff. Midwest ISO, like other ISOs and RTOs, was established under the auspices of the Federal Energy Regulatory Commission (FERC).[1] Midwest

[1] Doying Rebuttal, Ex. 4, Page 4, Lines 12-18.

ISO's operational area serves fifteen states and the Canadian province of Manitoba, and is located generally north and east of Missouri.[2]

2. Midwest ISO administers a common tariff, called an Open Access Transmission Tariff, that applies to all transmission services provided on the transmission facilities placed under the ISO's control by member electric companies. The common tariff applies the same rules to all transmission customers and avoids the "pancaking" of rates that occurs when power flows through transmission facilities operated by multiple entities and governed by multiple tariffs.[3]

3. An RTO provides wholesale transmission service on a regional basis. Such service meets two needs for transmission customers. First, it ensures the long-term deliverability of electricity from designated resources to load. In other words, the RTO provides a path by which electricity can be reliably transmitted from a generating facility to the customers that need that electricity. Second, the RTO facilitates short-term deliverability of electricity for economic transactions. That means, the RTO provides the transmission service required to deliver surplus electricity from lower-cost resources as a substitute for electricity from a higher-cost resource. That allows for the development of an electricity market in which those transactions can occur.[4]

4. Midwest ISO is not the only RTO capable of providing transmission services to Aquila. The FERC authorized Southwest Power Pool, Inc. to operate as a RTO beginning in October 2004.[5] Southwest Power Pool also provides independent reliability coordination and tariff administration through a FERC approved Open Access Transmission

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[2] Doying Rebuttal, Ex. 4, Page 4, Lines 7-8.
[3] Doying Rebuttal, Ex. 4, Pages 4-5, Lines 19-24, 1.
[4] Proctor Rebuttal, Ex. 12, Page 6, Lines 1-24.

Tariff.[6] Southwest Power Pool has fifty members serving more than four million customers in all or parts of eight southwestern states.[7]

5. Aquila is already a member of Southwest Power Pool. Its predecessor companies, Missouri Public Service Company and St. Joseph Light and Power joined that organization in 1951 and 1958, respectively.[8] Aquila currently contracts with Southwest Power Pool for certain services. Specifically, Aquila receives tariff administration, OASIS administration, available transmission capacity and total transmission capacity calculations, scheduling agent, and regional transmission planning from Southwest Power Pool.[9] Aquila does not, however, participate in Southwest Power Pool's EIS market.[10]

6. Aquila now pays Southwest Power Pool between $2 and $3 million per year for its membership in that organization.[11] If the Commission approves Aquila's application and it joins Midwest ISO, Aquila will have to terminate its relationship with Southwest Power Pool.[12] In doing so, Aquila would incur approximately $4 million in termination costs.[13]

7. Aquila also has a contractual relationship with Midwest ISO, currently receiving security coordination service from that organization.[14] If instead of joining

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[5] Monroe Surrebuttal, Ex. 9, Page 4, Lines 11-13.

[6] Monroe Surrebuttal, Ex. 9, Page 7, Lines 18-19.

[7] Monroe Surrebuttal, Ex. 9, Page 7, Lines 13-14. A map showing the service areas of Southwest Power Pool and Midwest ISO can be found at Janssen Rebuttal, Ex. 15, Schedule RJ-3.

[8] Monroe Surrebuttal, Ex. 9, Page 2, Lines 17-18.

[9] Odell Direct, Ex. 1, Page 6, Lines 10-12. A brief description of these services can be found at Transcript, Pages 98-100.

[10] Monroe Surrebuttal, Ex. 9, Page 5, Lines 14-15.

[11] Transcript, Page 101, Lines 11-21.

[12] Transcript, Page 110, Lines 23-25.

[13] Transcript, Page 111, Lines 1-14.

[14] Odell Direct, Ex. 1, Page 6, Lines 8-10.

Midwest ISO, Aquila chose to fully participate in Southwest Power Pool, it would have to end its relationship with Midwest ISO.[15]

Aquila's Commitment to Apply for Membership in Midwest ISO

8. In 1999, Aquila, then known as UtiliCorp, agreed to merge with St. Joseph Light & Power Company. That proposed merger required the approval of both this Commission and FERC. In its order approving the merger, FERC required the merged company to file a plan to join an RTO. At the time, Midwest ISO was the only FERC-approved RTO in the area, so Aquila entered into an agreement to join Midwest ISO on July 16, 2001.[16]

9. In 2001, Aquila applied to both FERC and this Commission for approval to transfer operational control of its transmission system to Midwest ISO. FERC approved that transfer, but Aquila withdrew its application before this Commission on January 2, 2002.[17] Aquila withdrew its application because AmerenUE, upon which Aquila is dependent for its physical connection to the Midwest ISO control area, had withdrawn from Midwest ISO, leaving Aquila with no physical connection to the RTO.[18]

10. In anticipation of turning operational control of its transmission system over to Midwest ISO, Aquila transferred security coordination responsibilities from Southwest Power Pool to Midwest ISO. As previously indicated, Midwest ISO continues to provide that service to Aquila on a contractual basis.[19]

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[15] Transcript, Page 111, Lines 18-24.
[16] Odell Direct, Ex. 1, Page 3, Lines 3-9.
[17] Odell Direct, Ex. 1, Pages 3-4, Lines 11-20, 1-4.
[18] Odell Direct, Ex. 1, Page 4, Lines 5-9.
[19] Odell Direct, Ex. 1, Page 4, Lines 12-15.

11. On December 20, 2002, Aquila made a filing with FERC challenging the reasonableness of certain administrative costs that Midwest ISO proposed to assess against Aquila.[20] Aquila and Midwest ISO settled that dispute, and one of the provisions of the settlement agreement required Aquila to once again apply to transfer operational control of its transmission facilities to Midwest ISO and diligently pursue approval of that application.

12. Aquila complied with that requirement of the settlement agreement by filing a second application with this Commission on June 20, 2003, again seeking authority to transfer control of its transmission facilities to Midwest ISO. After a number of delays, the Commission dismissed that application, without prejudice, to be refiled when additional system cost information became available.[21] On August 20, 2007, Aquila refiled its application, causing this case to open.

13. In its testimony, Aquila confirmed that it filed the application currently before the Commission to satisfy its obligation under the 2003 FERC settlement with Midwest ISO.[22] At the hearing, Aquila's witness, Dennis Odell, indicated Aquila's concern that it would be required to pay financial penalties to Midwest ISO if it breached its contractual obligation to again apply for membership in Midwest ISO.[23] When asked at the hearing whether Aquila would have applied for membership in Midwest ISO in the absence of its obligation under the 2003 settlement, Odell replied that he did not know.[24]

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[20] Odell Direct, Ex. 1, Page 4, Lines 15-17.

[21] Odell Direct, Ex. 1, Page 5, Lines 1-7. See also, *In the Matter of Aquila, Inc. d/b/a Aquila Networks – MPS and Aquila Networks – L&P's Application to Join the Midwest Independent Transmission System Operator, Inc.,* Order Closing Case, Case No. EO-2003-0566, May 12, 2005.

[22] Odell Direct, Ex. 1, Page 6, Lines 17-20.

[23] Transcript, Page 95, Lines 5-16.

[24] Transcript, Pages 114-115, Lines 18-25, 1-2.

The CRA International Study

14. As part of its application, Aquila submitted the results of a cost-benefit analysis performed by CRA International. CRA is an independent consulting firm hired by Aquila to analyze the costs and benefits of Aquila's various options for joining, or not joining, an RTO.[25] After consulting with a stakeholder group that included Midwest ISO, Southwest Power Pool, Staff, and Public Counsel,[26] Aquila instructed CRA to consider three scenarios: membership in Midwest ISO; membership in Southwest Power Pool; and a move to a stand-alone status in which Aquila would perform transmission and reliability related functions on its own.[27] CRA completed the study on March 28, 2007, and Aquila submitted a copy of the study as part of its application, and as an attachment to Dennis Odell's direct testimony.[28]

15. To conduct its study, CRA ran a detailed economic dispatch and production cost model that simulates the operation of the electric power system. The model, known as GE MAPS, determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element in the transmission system, and the locational marginal price (LMP) for each generator and load area.[29] Membership in an RTO reduces impediments to Aquila's purchases and sales of energy and capacity to other RTO members, yielding "trade benefits" to Aquila. Those "trade benefits" are offset by additional administrative charges Aquila would incur by being a member of an RTO.[30]

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[25] Odell Direct, Ex. 1, Page 7, Lines 1-3.
[26] Transcript, Page 121, Lines 7-21.
[27] Odell Direct, Ex. 1, Page 7, Lines 3-5.
[28] Odell Direct, Ex. 1, Schedule DO-3.
[29] Odell Direct, Ex. 1, Schedule DO-3, Page 2.
[30] Odell Direct, Ex. 1, Schedule DO-3, Page 2.

16. The study concluded that over the ten-year study period, the net benefit to Aquila of joining Midwest ISO was $21.1 million, compared to moving to a stand-alone status. However, the study also concluded that the net benefit to Aquila of joining Southwest Power Pool's RTO over the same period amounted to $86.9 million, again compared to a stand-alone status.[31]

17. Given the greater net benefits shown by the study to result from Aquila's membership in the Southwest Power Pool RTO, several parties, including Southwest Power Pool, urge the Commission to reject Aquila's application to join Midwest ISO so that the company can instead apply to join Southwest Power Pool's RTO. Aquila, using an argument the Commission will address in detail in the conclusions of law section of this Report and Order, contends the Commission should not consider the Southwest Power Pool alternative in ruling on its application to join Midwest ISO. In addition, Midwest ISO and the City of Independence challenge the factual basis of the CRA study's conclusion that the net financial benefits Aquila would attain from joining Southwest Power Pool's RTO would significantly exceed the net benefits of joining Midwest ISO.

18. A large part of the challenge to the accuracy of the CRA study's analysis of the Aquila in Southwest Power Pool alternative is centered on the study's assumption that Southwest Power Pool and Midwest ISO will operate similar markets over the long-term time frame used in the study.[32] In fact, Midwest ISO currently operates both a real-time market and a day-ahead market, while Southwest Power Pool operates only a real-time market.[33] Southwest Power Pool is currently evaluating whether a day-ahead market

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[31] Odell Direct, Ex. 1, Schedule DO-3, Page 4, Table 1.
[32] Odell Direct, Ex. 1, Schedule DO-3, Page 8.
[33] Transcript, Page 151, Lines 11-14.

would be cost effective and the earliest it could implement such a market would be between the end of 2010 and 2012.[34] The existence of additional markets can result in increased trade benefits for Aquila.[35] As a result, the study's assumption of similar markets could overstate the benefits to Aquila of membership in Southwest Power Pool, at least in the short-run.

19. That is not, however, a serious flaw in the study. When evaluating a company's request to join an RTO it is appropriate to consider the long-run costs and benefits of that membership, not short-term variations. In the long run, it is appropriate to assume Southwest Power Pool will implement these additional markets if doing so proves cost beneficial.[36] To account for the short-term variation, the CRA study assumed not only that Midwest ISO and Southwest Power Pool offered similar markets; it also assumed that the two companies charged their members identical administrative charges to operate those markets. While additional markets tend to increase trade benefits, the additional markets also increase administrative charges, resulting in a rough balance at least in the short-term.[37]

20. Midwest ISO engaged the services of an economic consultant, Johannes P. Pfeifenberger[38], to further evaluate the CRA study. Pfeifenberger concluded the CRA study tends to overstate the benefits Aquila would achieve from joining Southwest Power Pool instead of Midwest ISO. In large part, Pfeifenberger's criticism of the results of the

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[34] Monroe Surrebuttal, Ex. 9, Page 17, Lines 14-21.
[35] Transcript, Page 288, Lines 12-14.
[36] Proctor Rebuttal, Ex. 12, Page 25, Lines 15-16.
[37] Transcript, Page 110, Lines 13-22.
[38] Pfeifenberger is a Principal and Director of The Brattle Group, an economic consulting firm. He has an M.A. in Economics and Finance from Brandeis University and an M.S. in Electrical Engineering with a specialization in Power Engineering and Energy Economics from the University

CRA study is centered on the model's dispatch of the Dogwood combined-cycle merchant generating plant, which is located in Aquila's service territory.[39]

21. Pfeifenberger contends the CRA study greatly over-commits the Dogwood plant in the "Aquila Stand Alone" and the "Aquila in Midwest ISO" simulation scenarios, but not in the "Aquila in Southwest Power Pool" scenario. This over-commitment of the Dogwood plant is uneconomic, indicating greater costs for Aquila in those scenarios. According to Pfeifenberger, the presence of these greater costs unrealistically indicates greater benefits to Aquila from joining Southwest Power Pool since those uneconomic costs are not included in the "Aquila in Southwest Power Pool" scenario.[40]

22. However, as Staff's witness, Dr. Michael Proctor explains, the heavy commitment of the Dogwood plant in the Aquila in Midwest ISO scenario reflects a real problem, not a problem with the modeling. Because of limited transmission between Midwest ISO and the resulting high levels of congestion, energy imports from the Midwest ISO generation pool were not available for unit commitment and consequently, the Dogwood plant had to be committed more to meet Aquila's load.[41] Thus, the model is demonstrating a real drawback to Aquila's proposed membership in Midwest ISO. It simply does not have adequate transmission links with the rest of Midwest ISO.

Aquila's Limited Interconnection with Midwest ISO

23. Aquila is linked to Midwest ISO by just two tie line connections with AmerenUE, which is a member of Midwest ISO. Those two tie lines have a summed MVA

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of Technology, Vienna, Austria. Pfeifenberger Rebuttal, Ex. 5, Page 1.

[39] The Dogwood Plant was formerly known as the Aries Plant and is sometimes referred to as such in the testimony.

[40] Pfeifenberger Rebuttal, Ex. 5, Pages 8-9, Lines 20-23, 1-7.

[41] Proctor Cross Surrebuttal, Ex. 13, Page 12, Lines 12-15.

capacity[42] of 1,207. In contrast, Aquila is linked to Southwest Power Pool by 14 tie lines with a summed MVA capacity of 5,915.[43] Thus, the megawatt import capability from Southwest Power Pool into Aquila is much higher than from Midwest ISO into Aquila.[44] This greater interconnection with Southwest Power Pool allows Aquila to displace expensive generation in its own control area with less expensive purchased power from the Southwest Power Pool control area, resulting in cost savings for Aquila.[45]

AmerenUE's Decision to Remain in Midwest ISO

24. As indicated, Aquila's two tie lines connecting it to Midwest ISO connect through AmerenUE. During the course of this case, AmerenUE was considering whether it would choose to remain a member of Midwest ISO. If AmerenUE withdrew from Midwest ISO, Aquila would no longer have any direct transmission connection to Midwest ISO and it would be difficult for it to continue to participate in Midwest ISO.[46] However, while this case was awaiting decision, the Commission approved a stipulation and agreement that will allow AmerenUE to remain in Midwest ISO at least through 2011.[47]

The Merger with KCPL

25. One other development that occurred during the course of this case will have a definite impact on the possible benefits to Aquila from joining Midwest ISO. On July 1,

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[42] MVA stands for mega volt amperes, a measure of the transmission capacity of a power line. Janssen Rebuttal, Ex. 15, Page 12, Footnote 8.

[43] Proctor Rebuttal, Ex. 12, Page 29, Table 1.

[44] Proctor Rebuttal, Ex. 12, Page 30, Lines 19-21.

[45] Odell Direct, Ex. 1, Schedule DO-3, Page 5.

[46] Transcript, Page 107, Pages 11-25.

[47] *In the Matter of the Application of Union Electric Company for Authority to Continue the Transfer of Functional Control of its Transmission System to the Midwest Independent Transmission System Operator, Inc.,* Case No. EO-2008-0134, Order Approving Stipulation and Agreement, issued September 9, 2008.

2008, in Case No. EM-2007-0374, the Commission approved the acquisition of Aquila by Great Plains Energy Incorporated, the parent company of Kansas City Power & Light Company (KCPL).[48] KCPL is currently a member of Southwest Power Pool.[49] In approving the merger, the Commission recognized that the merged entity controlling both KCPL and Aquila would realize significant synergy benefits from operating both companies in the same RTO.[50] Those merger synergies could be lost if Aquila joined Midwest ISO while KCPL remained a member of Southwest Power Pool.

CONCLUSIONS OF LAW

The Missouri Public Service Commission has reached the following conclusions of law:

1. Aquila, Inc., is an "Electrical Corporation" and "Public Utility", as those terms are defined at Subsections 386.020 (15) and (42), RSMo Supp. 2007. As such, it is subject to regulation by this Commission.

2. Section 393.190.1, RSMo 2000 requires a regulated electric utility, such as Aquila, to obtain permission from the Commission before transferring control of any part of its transmission system. Specifically, the relevant portion of that section states:

> No gas corporation, electrical corporation, water corporation or sewer corporation shall hereafter sell, assign, lease, transfer, mortgage or otherwise dispose of or encumber the whole or any part of its franchise, works or system, necessary or useful in the performance of its duties to the public, nor by any means, direct or indirect, merge or consolidate such works or system, or franchises, or any part thereof, with any other corporation, person or public

[48] *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Aquila, Inc., for Approval of the Merger of Aquila, Inc., with a Subsidiary of Great Plains Energy Incorporated and for Other Related Relief.*, Case No. EM-2007-0374, Report and Order, issued July 1, 2008.

[49] Transcript, Page 106, Lines 16-17.

[50] *Id.* at Pages 196-197.

> utility, without having first secured from the commission an order authorizing it so to do.

3. The statute does not establish a specific standard for the Commission to use in deciding whether to authorize an electric utility to transfer control of its transmission system. However, that controlling standard was established by the Missouri Supreme Court in a 1934 decision.

4. In its decision in *State ex rel. City of St. Louis v. Public Service Commission*,[51] the Missouri Supreme Court held that in deciding to approve a proposed transfer of stock in a Missouri utility, the Commission did not need to find that the proposed transaction would benefit the public interest. Instead, the court quoted the Supreme Court of Maryland in holding:

> To prevent injury to the public, in the clashing of private interest with the public good in the operation of public utilities, is one of the most important functions of Public Service Commissions. It is not their province to insist that the public shall be benefited, as a condition to change of ownership, but their duty is to see that no such change shall be made as would work to the public detriment. *'In the public interest,' in such cases, can reasonably mean no more than 'not detrimental to the public'* (emphasis added).[52]

Thus, before it can approve Aquila's proposal to transfer control of its transmission system to Midwest ISO, the Commission must determine that the proposed transfer would not be detrimental to the public interest.

5. The Commission has also incorporated the "not detrimental to the public" standard into its own rules. Commission Rule 4 CSR 240-3.110(1)(D) requires an electric utility seeking authority to sell, assign, lease or transfer assets to state "the reasons the proposed sale of the assets is not detrimental to the public interest."

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[51] 73 S.W.2d 393 (Mo banc 1934)

[52] Id. at 459-460. (*Quoting, Electric Public Utilities Co. v. Public Service Commission*, 154 Md 445,

6. Clearly, "not detrimental to the public interest" is the standard by which this Commission must weigh Aquila proposal to transfer control of its transmission system to Midwest ISO.

7. In deciding whether a proposed transaction is "not detrimental to the public interest", the Commission must consider and decide all the necessary and essential issues.[53]

8. One necessary and essential issue the Commission must consider is the lost opportunity cost associated with allowing Aquila to join Midwest ISO instead of Southwest Power Pool.

9. When alternatives with economic impacts are presented, an evaluation of the detriments of a particular alternative to the public interest must include consideration of the opportunity cost of not pursuing any available alternatives. There do not appear to be any Missouri state court cases directly announcing this principle, but it is a well-established aspect of Federal administrative law.[54]

10. Missouri's Western District Court of Appeals has recently held that the Commission is not limited to narrowly considering the possible benefits of a presented alternative when other alternatives are also important. In *Environmental Utilities, LLC v. Public Service Commission*,[55] the court upheld the Commission's rejection of a proposed sale of a part of the sewer system of a troubled utility, because, while there were benefits to those customers who would be served by the purchaser, the benefits of the sale of the

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140 A. 840, 844, (Md. 1928).

[53] *State ex rel. AG Processing, Inc. v. Public Service Commission*, 120 S.W.3d 732 (Mo. banc 2003).

[54] *For example see*, *Victor Broadcasting v. FCC*, 722 F2d 756 (DC Cir. 1983).

[55] 219 S.W.3d 256 (Mo. App. W.D. 2007).

entire system would be greater, and would be lost if the incomplete transaction were allowed to proceed.

11. Obviously, if Aquila transfers its transmission system to Midwest ISO and joins that RTO, it cannot join Southwest Power Pool's RTO. Foregoing greater financial benefits that could be obtained from joining Southwest Power Pool to instead accept lesser financial benefits from joining Midwest ISO is a potential detriment to the public that the Commission must consider.

DECISION

Based on the facts as it has found them, and its conclusions of law, the Commission has reached the following decision.

Aquila's proposal to transfer operational control of its transmission assets to Midwest ISO would cause a detriment to the public interest and on that basis, Aquila's application will be denied.

The detriment to the public interest occurs, in part, because Aquila's plan to join Midwest ISO would preclude it from joining Southwest Power Pool. As established by the independent and credible cost benefit analysis performed by CRA International, the net benefit to Aquila of joining Midwest ISO would be approximately $65 million less over ten years than the net benefit it could obtain by joining Southwest Power Pool.

Midwest ISO and the City of Independence challenged the conclusions of that study, but their arguments are not persuasive. Midwest ISO currently offers a more fully developed day-ahead energy market to its member utilities than does Southwest Power Pool. However, Aquila's decision to join an RTO is a long-term decision, so it is appropriate to place greater emphasis on the long-term results of that decision. Over the long-term, Southwest Power Pool's markets are likely to catch-up with those offered by Midwest ISO, and the CRA International study appropriately accounts for those differences in the short-term.

Midwest ISO's other criticism of the CRA International Study focuses on the model's allegedly unrealistic dispatch of the Dogwood plant in the "Aquila in Midwest ISO" scenario. However, rather than highlighting a problem with the study's model, this criticism points out a real life problem with Aquila's proposal to join Midwest ISO. Aquila's existing transmission connections to the rest of Midwest ISO, through its interconnections with AmerenUE, simply are not as extensive as its connections to Southwest Power Pool. The additional transmission congestion over those limited connections that would result if Aquila joined Midwest ISO is an additional detriment to the public.

Finally, the public, specifically, Aquila's ratepayers, will suffer one more detriment if Aquila is allowed to join Midwest ISO, thereby excluding it from membership in Southwest Power Pool. Many of the financial benefits ratepayers are likely to see from the recent acquisition of Aquila by the parent corporation of KCPL are predicated on Aquila and KCPL being members of the same RTO. KCPL is already a member of Southwest Power Pool so if Aquila is allowed to join Midwest ISO, many of those financial benefits will be lost.

Nevertheless, Aquila has asked for permission to join Midwest ISO. Under other circumstances, the Commission might be inclined to defer to the business judgment of Aquila if there were a good reason to do so. However, it is clear that the only reason Aquila has applied to join Midwest ISO instead of Southwest Power Pool is its obligation to do so under a six-year-old agreement with Midwest ISO in a case before FERC. This

Commission is not bound by that agreement, and its existence is not a sufficient reason to defer to Aquila's judgment. The Commission will not allow the existence of that agreement to harm Aquila's Missouri ratepayers by allowing Aquila to enter into a less than optimal agreement with Midwest ISO.

The CRA International cost-benefit study shows that Aquila, and thereby its ratepayers, will benefit if Aquila joins an RTO. However, Midwest ISO is not the appropriate RTO for Aquila to join. The question of whether Aquila should join Southwest Power Pool is not properly before the Commission in this case, so the Commission will not now order Aquila to apply to join that RTO. However, Aquila has now satisfied its contractual obligation by applying for authority to transfer operational control of its transmission facilities to Midwest ISO and diligently pursuing approval of that application. The Commission has rejected that application on its merits. Aquila is now free to apply to the Commission for authority to join whichever RTO best meets its needs.

IT IS ORDERED THAT:

1. Aquila, Inc.'s Application for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc. is rejected.

2. This Report and Order shall become effective on October 19, 2008.

BY THE COMMISSION

Colleen M. Dale
Secretary

(S E A L)

Murray, Clayton, Jarrett, Gunn, CC., concur;
Davis, Chm., concurs with separate concurring opinion attached;
and certify compliance with the
provisions of Section 536.080, RSMo.

Dated at Jefferson City, Missouri,
on this 9th day of October, 2008.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks – MPS and Aquila Networks – L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.	))))))	**Case No. EO-2008-0046**

CONCURRING OPINION OF CHAIRMAN JEFF DAVIS

I respectfully concur with the decision of the majority in this case and their rationale. However, I wish to supplement their reasoning with my own additional line of reasoning.

At best, regional transmission authorities (RTOs) were in their infancy at the time the Federal Energy Regulatory Commission (FERC) issued its original order in 2000.[1] FERC required Aquila to propose to transfer operational control of its transmission facilities no later than December 15, 2001.[2] Although Southwest Power Pool (SPP) was performing various RTO functions at that time, MISO was the only FERC-approved RTO in the area, as such, Aquila applied to join MISO.[3] Much has happened since then and this commission does a great job of setting those facts out in painstaking detail.

Requiring a utility to join an RTO is one thing, requiring a utility to join one specific RTO, even if it's the only one in existence in a given area, when the regulatory environment

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[1] *See* Utilicorp United Inc., and St. Joseph Light & Power Co., 92 FERC P 61228, 61233 (2000), where FERC acknowledged there were "likely to be significant changes in the structure and configuration of the regional transmission entities in the area."

[2] *Id*. at 61234.

[3] Odell Direct, Ex. 1, Page 3, Lines 3-9. Note: Southwest Power Pool (SPP) did not become an RTO until 2004.

is in a state of flux, is another. This is especially true when you consider the following factors: the lack of interconnectivity between Aquila and MISO which should have been as apparent to FERC then as it is to us now; many of those functions were already being performed by another organization, SPP; and, at the time, Aquila management decisions were driven more by a sense of political expediency to curry favor with FERC to obtain merger approval rather than thoughtful analysis. For these reasons, the condition requiring Aquila to seek membership in an organization before the RTO market was settled should have been void against public policy and this question should not even be before this commission.

In conclusion, Aquila, FERC, MISO and the City of Independence could have all exercised better discretion in this matter and I would urge the following thoughts for future consideration:

(1) FERC should have allowed more time for other RTOs to develop instead of just requiring Aquila to join one. It's just another example of FERC firing the gun without aiming in an effort to get something done;

(2) MISO should be less focused on empire building and more focused on taking care of the numerous issues they face in trying to serve a vast territory that already stretches from Pennsylvania to Montana and from Manitoba, Canada to Southeast Missouri;

(3) The City of Independence should carefully reconsider their position that MISO membership is more beneficial to their constituents than another RTO. Taking into account everything in the record in this case, everything I have learned as a member of this commission and through my participation as a member of the

Organization of MISO States (OMS) and the Regional State Committee (RSC) for SPP, it is my position that MISO membership for Aquila could be, in fact, an economic detriment to Independence and the other municipal utilities in the Aquila footprint; and

(4) With regard to RTOs, bigger does not always mean better in terms of better quality or lower costs. In theory, more members in MISO should lead to lower transaction costs across the footprint but I have yet to see those benefits materialize. Moreover, it costs more to maintain a far-flung system. A larger footprint contains more stakeholders whose diverse views make it increasingly difficult to reach agreement on important policy issues. Small utilities like Aquila and the transmission-dependent municipal utilities (TDUs) located inside Aquila's footprint are disadvantaged in terms of their ability to even monitor MISO activity on a going forward basis much less lobby for changes to the system.

Accordingly, for all of the aforementioned reasons, I concur with the decision of the majority to reject Aquila's application to transfer operational control of certain transmission assets to MISO in this case.

Respectfully submitted,

Jeff Davis
Chairman

Dated at Jefferson City, Missouri,
on this 9th day of October, 2008.

Item KIUC MISO 1-6) ***Refer to page 22, lines 16-18 of your direct testimony. Has MISO ever conducted a member-specific benefit study of any entity for the purpose of quantifying the amount of costs and benefits, measured in dollars, that would be realized by an entity as a result of its membership in MISO? If your response is Yes, please provide Documents and Studies, including workpapers, of each Study:***

(a) ***Please identify the study and provide an electronic and hard copy of such Study, with all formulas intact; and,***

(b) ***Please include in your response whether the ratio of peak load of the specific member to aggregate peak load of all MISO participants was utilized to determine the share of overall MISO benefits to members, realized by a specific entity from its participation in MISO as a member.***

Response) Yes. In 2003, in the LG&E withdrawal case before this commission, Case No. 2003-00266, the Midwest ISO presented testimony regarding its opinion of the economic benefits LG&E would forego by leaving the Midwest ISO. That testimony was prepared before the Midwest ISO energy market had been established, the ancillary services market had begun, and the Value Proposition had been developed. The methodology used, and conclusions reached, by the witness Ronald McNamara would be irrelevant to analyzing the economic benefits of membership today.

(a) Pursuant to the Midwest ISO document retention policy, no underlying spreadsheets or other work papers from that study remain in the company files (Dr. McNamara left the Midwest ISO in 2006). The original testimony and supporting exhibits should be available in the files of the Kentucky Public Service Commission.

(b) No, a ratio of peak load was not the methodology used by Dr. McNamara, because the Value Proposition had not been developed at that time. See also Midwest ISO Response to KIUC1-Q.1-5, in which the ratio of peak demand method was used to project a portion of total Value Proposition benefits. As stated in my original testimony on page 22, lines 16-18, the Midwest ISO in its present configuration does not attempt to quantify specific benefits to specific members (or potential members) because we do not fully understand those entities' economics. We have, since the development of the Value Proposition, provided testimony indicating where value may be found, and continue to believe that the Value Proposition is indicative of where and how much value might be available

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-7) ***Refer to page 34-35 of your direct testimony. Please explain and describe the ongoing financial obligation of a MISO participant to continue to fund, after it has withdrawn from the organization, (a) the cost of MTEP or (b) other MISO costs.***

Response) The exiting party would maintain responsibility for its share of the allocation of projects approved during the party's membership. The amount owed would be that defined under the tariff at the time the projects were approved. All other Midwest ISO costs that are allocated to the exiting member would be included in the exit fee. Exit fee estimates were provided in previously submitted testimony.

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-8) ***Please provide all Documents and Studies relating to the issue of "grandfathering" the following Big Rivers wholesale contracts:***

(a) Kenergy Corp;

(b) Jackson Purchase Meade County;

(c) Kenergy Corp., for the benefit of Alcan Primary Products Corporation; and,

(d) Kenergy Corp., for the benefit of KIUC Aluminum of Kentucky General Partnership.

Please include in your response the rationale supporting the grandfathering determination in each case.

Response) The only "Documents and Studies" relating to grandfathering of Big Rivers' wholesale contracts are the Midwest ISO Tariff, relevant FERC orders, and a memorandum of counsel. The Midwest ISO claims attorney-client privilege for the memorandum of counsel, but the following proposed treatment of the contracts in question is based upon the terms of the Tariff and the relevant orders of the FERC, which orders are attached to this response:

(a) Kenergy Corp—"Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Green River Electric Corporation, as amended and "Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Henderson-Union, as amended were deemed to be eligible for Option A or Option C GFA status because they were entered into (with the predecessors in interest of Kenergy) prior to September 16, 1998, as set forth in the definition of "Grandfathered Agreement" and in Section 38.8.3 of the Midwest ISO Tariff.

(b) Jackson Purchase—"Wholesale Power Agreement" dated October 14, 1977, between Big Rivers and Jackson Purchase Rural Electric Cooperative Corporation, as amended was deemed to be eligible for Option A or Option C GFA status because it was entered into prior to September 16, 1998, as set forth in the definition of "Grandfathered Agreement" and in Section 38.8.3 of the Midwest ISO Tariff.

(c) Meade County—"Wholesale Power Contract" dated June 11, 1962, between Big Rivers and Meade County Rural Electric Cooperative Corporation, as amended was deemed to be eligible for Option A or Option C GFA status because it was entered into prior to September 16, 1998, as set forth in the definition of "Grandfathered Agreement" and in Section 38.8.3 of the Midwest ISO Tariff.

(d) Kenergy Corp., for the benefit of Alcan Primary Products Corporation—This agreement is not eligible for GFA treatment because it was entered into after September 16, 1998, as set forth in the definition of "Grandfathered Agreement" in the Midwest ISO Tariff.

(e) Kenergy Corp., for the benefit of Century Aluminum of Kentucky General Partnership--This agreement is not eligible for GFA treatment because it was entered into after September 16, 1998, as set forth in the definition of "Grandfathered Agreement" in the Midwest ISO Tariff.

A contract between a Transmission Owner and its affiliates or cooperative members is not eligible for Carved Out GFA status for new members, following a December 15, 2009 order of the FERC. For each of the contracts that qualify for GFA treatment, Section 38.8.3 provides Option A or Option C treatment, as described in Section 38.8.3, or conversion to OATT service under the Midwest ISO tariff. Note that the GFA status, or lack of it, does not affect the energy supply price or obligation of an agreement, but rather the contract obligation that deals with the transmission of that energy.

Witness) **Clair J. Moeller**

ATTACHMENT 1

108 FERC ¶ 61,236
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher
and Suedeen G. Kelly.

Midwest Independent Transmission System Operator, Inc.	Docket Nos. ER04-691-000 ER04-106-002
Public Utilities With Grandfathered Agreements in the Midwest ISO Region	Docket No. EL04-104-000

ORDER ADDRESSING TREATMENT OF GRANDFATHERED AGREEMENTS IN THE MIDWEST ISO ENERGY MARKETS, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued September 16, 2004)

TABLE OF CONTENTS

1. On March 31, 2004, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) filed a proposed Open Access Transmission and Energy Markets Tariff (TEMT) pursuant to section 205 of the Federal Power Act (FPA).[1] The proposed TEMT contains the terms and conditions necessary to implement a market-based congestion management program and energy spot markets, including a Day-Ahead Energy Market and a Real-Time Energy Market (collectively, Energy Markets), with locational marginal pricing (LMP) and Financial Transmission Rights (FTRs) for hedging congestion costs. In its application, the Midwest ISO estimated that up to 40,000 MW of transmission service capacity (approximately 40 percent of total Midwest ISO load) is provided under an estimated 300 grandfathered agreements (GFAs) currently effective in the Midwest ISO region.[2] The Midwest ISO argued that allowing GFA-holders scheduling rights similar to their current practice would require a physical reservation, or "carve-out," of transmission capacity in the Day-Ahead Energy Market and until the scheduling deadline prior to real-time dispatch. It stated that this carve-out would impair the reliability of the operation of its markets and would impose additional financial costs on parties to non-GFA transactions. Therefore, the Midwest ISO proposed to require GFA parties to schedule and settle their GFA transactions under the Midwest ISO's Energy and FTR Markets through one of three options.[3]

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[1] 16 U.S.C. § 824d (2000).

[2] *See* Midwest ISO's March 31, 2004 TEMT filing at 9-10 (March 31 Filing).

[3] As discussed more fully below, Option A of the TEMT requires the GFA Responsible Entity to nominate and hold FTRs in order to transact under GFAs. The Midwest ISO assesses congestion charges and the cost of losses for all transactions under the GFA. Option B provides that the GFA Responsible Entity will not nominate or receive FTRs. The Midwest ISO will charge the GFA Responsible Entity the cost of congestion for all transactions pursuant to the GFA, but, if the GFA Scheduling Entity submits the bilateral transaction schedule a day ahead, the Midwest ISO will credit back to the GFA Responsible Entity the costs of congestion resulting from day-ahead

(continued)

2. On May 26, 2004, the Commission issued an order on the Midwest ISO's proposed TEMT and, among other things, initiated, under section 206 of the FPA,[4] a three-step process to address the treatment of transmission service provided under the GFAs in the Midwest ISO Energy and FTR Markets and offered an option for GFA parties to settle.[5] Further, the Commission set the date for implementation of the Energy Markets at March 1, 2005.[6]

3. The purpose of this order, Step 3 of the process, is to address how GFAs will be treated in the Midwest ISO Energy and FTR Markets. We have analyzed the contract information resulting from the fact-finding investigation of GFA contract terms in Steps 1 and 2 of the process and have divided the GFAs into several categories with differing consequences for their treatment in the Midwest ISO's Energy and FTR Markets, based either on their election to settle, actions by the presiding judges in the hearing held in Step 2, or our determinations in this order.

4. As discussed below, while the Midwest ISO had initially estimated that up to 40,000 MW of transmission service (40 percent of total Midwest ISO load) is provided under the GFAs, the results of the fact finding investigation conducted in Steps 1 and 2 indicate that only approximately 25,000 MW of transmission service (23 percent of total Midwest ISO load) is provided under 229 GFAs that will remain in effect on March 1, 2005, when the Midwest ISO commences operation of its Energy Markets. Of this 25,000 MW of transmission service, by our actions in this order, approximately 9,700 MW (9 percent of total MISO load) will participate in the Midwest ISO's Energy Markets as a result of GFA parties' voluntary election of one of the Midwest ISO's three options proposed for scheduling and financially settling GFA transactions or by voluntarily converting their service to the TEMT. Another approximately 5,000 MW

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schedules that the GFA Responsible Entity clears in the day-ahead market. The Midwest ISO will also charge the GFA Responsible Entity the cost of losses for all transactions under the GFA, then, if the GFA Scheduling Entity has timely submitted a conforming schedule for the GFA, credit back to the GFA Responsible Entity the difference between marginal losses and system losses at the GFA source and sink points. Option C requires the GFA Responsible Entity to pay the costs of congestion for all GFA transactions.

[4] 16 U.S.C. § 824e (2000).

[5] Midwest Independent Transmission System Operator, Inc., 107 FERC ¶ 61,191 (2004) (Procedural Order).

[6] *Id.* at P 3.

(4.5 percent of total MISO load), representing those GFAs for which unilateral modification is subject to the just and reasonable standard of review, will also participate in the Midwest ISO's markets pursuant to the requirements of this order. This leaves only approximately 10,385 MW (9.6 percent of total Midwest ISO load) that the Commission finds can be "carved-out" and therefore not participate in the Midwest ISO's Energy and FTR Markets, representing transmission service provided under: (1) those GFAs for which the parties have explicitly provided that unilateral modification is subject to the *Mobile-Sierra*[7] public interest standard of review; (2) those GFAs that are silent with respect to the standard of review; and (3) those GFAs providing for transmission service by an entity that is not a public utility.

5. We find that the Midwest ISO will be able to reliably operate its Energy and FTR Markets with this carve-out of GFAs given the relatively small amount of transmission service (less than 10 percent of total Midwest ISO load) involved. Moreover, we find that, even with this carve-out, the Midwest ISO's Energy and FTR Markets will be more reliable and efficient overall than the market currently in place in the region.

6. Finally, we decide upon the applicability of Schedule 16, FTR Service, and Schedule 17, Energy Market Service, to transactions taking place under GFAs. Specifically, we find that Schedule 16 charges should apply to GFA transactions to the extent that those transactions are subject to the Midwest ISO Energy Markets and GFA parties have nominated FTRs for those transactions or otherwise receive a hedge in the Day-Ahead Energy Markets for such transactions. GFA transactions would not otherwise be subject to Schedule 16 charges. With respect to Schedule 17 charges, we find that those charges should apply to all GFA transactions on the same basis that they apply to non-GFA transactions. For GFAs subject to the Midwest ISO Energy Markets, the Schedule 16 and 17 charges will be the responsibility of the GFA Responsible Entity. For carved-out GFAs, Schedule 17 charges will be the responsibility of the Transmission Owner or Independent Transmission Company (ITC) Participant taking service under the Midwest ISO Tariff to meet its transmission service obligations under the GFA.

7. Our action here will ensure that the Midwest ISO's Energy Markets start on time with the benefit of a comprehensive approach to GFAs and a clear definition of their relationship to the new Energy Markets. Today's order benefits customers by taking measures necessary to ensure that the GFA parties and other market participants are treated fairly and reasonably upon the start of the Midwest ISO's Energy Markets on March 1, 2005. We also expect that this order will provide parties to the GFAs and the

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[7] *See* United Gas Pipe Line Company v. Mobile Gas Service Corp., 350 U.S. 332 (1956) (*Mobile*); FPC v. Sierra Pacific Power Company, 350 U.S. 348 (1956) (*Sierra*).

Midwest ISO with the framework they need to begin the FTR allocation process on schedule, thereby meeting a deadline critical to an on-time start to the Energy Markets.

8. This order first addresses the issue of the impacts of GFAs on the reliability and economic efficiency of the Midwest ISO Energy Markets, followed by a discussion of the GFA sub-categories and their treatment, and then it addresses our determinations on the conversion options and the treatment of carved-out GFAs before and after the transition period. The order finishes by addressing the Midwest ISO's May 26, 2004 compliance filing proposing revisions to Attachment P (List of GFAs).

I. Background

9. By order issued September 16, 1998, the Commission conditionally approved the formation of the Midwest ISO.[8] The Formation Order also conditionally accepted for filing an open access transmission tariff (OATT) for the Midwest ISO (Midwest ISO Tariff), and an Agreement of Transmission Facilities Owners to Organize the Midwest Transmission System Operator, Inc. (Midwest ISO Agreement), and established hearing procedures. In addition, the Commission granted conditional approval for ten public utilities to transfer operational control of their jurisdictional transmission facilities to the Midwest ISO, and deferred placement under the Midwest ISO Tariff of transmission service for the Transmission Owners' bundled retail load and service provided under wholesale bilateral GFAs for six years.[9]

10. Subsequently, in an order on initial decision resulting from the hearing, the Commission found that the Midwest ISO must be the sole provider of transmission service over its system and required that Transmission Owners and ITC Participants take service under the Midwest ISO Tariff to serve their bundled retail load and meet their obligation under the GFAs.[10]

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[8] Midwest Independent Transmission System Operator, Inc., *et al.*, 84 FERC ¶ 61,231 (Formation Order), *order on reconsideration*, 85 FERC ¶ 61,250, *order on reh'g*, 85 FERC ¶ 61,372 (1998).

[9] Formation Order at 62,167, 62,169-70. *See also* Midwest ISO Agreement at Appendix C.II.A.1.f.

[10] Midwest Independent Transmission System Operator, Inc., *et al.*, Opinion No. 453, 97 FERC ¶ 61,033 at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand,* 102 FERC ¶ 61,192 (2003), *reh'g denied,* 104 FERC ¶ 61,012 (2003), *aff'd sub nom.* Midwest ISO Transmission Owners, *et al.* v. (continued)

11. On December 20, 2001, the Commission found that the Midwest ISO's proposal to become a Regional Transmission Organization (RTO) satisfied the requirements of Order No. 2000,[11] and thus granted the Midwest ISO RTO status.[12] The Commission also determined that the Midwest ISO's proposal for congestion management was a reasonable initial approach to managing congestion that satisfied the requirements of Order No. 2000 for Day 1 operation of an RTO, but directed it to develop a market-based approach to manage congestion to satisfy the requirements for Day 2 operations under Order No. 2000.

12. Subsequently, the Midwest ISO filed a petition for declaratory order – the culmination of over a year of stakeholder discussions[13] – that sought the Commission's endorsement of the general approach represented in three proposed market rules (Market Rules). The Market Rules proposed in the filing would provide for: (1) a security-constrained, centralized bid-based scheduling and dispatch system (*i.e.*, day-ahead and real-time market rules); (2) FTRs for hedging congestion costs; and (3) market settlement rules. The Commission approved the general direction of the Midwest ISO's proposals, reserving judgment on some issues and providing guidance on others.[14] The Commission affirmed many of its conclusions on rehearing.[15]

13. On July 25, 2003, the Midwest ISO filed a proposed TEMT pursuant to section 205 of the FPA (July 25 Filing). Like the March 31 Filing, the July 25 Filing included

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FERC, 373 F.3d 1361 (D.C. Cir. 2004).

[11] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (2000), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[12] Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 (2001) (RTO Order), *reh'g denied*, 103 FERC ¶ 61,169 (2003).

[13] *See* Doying testimony at 4.

[14] Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,196 (2003) (Declaratory Order).

[15] Midwest Independent Transmission System Operator, Inc., 103 FERC ¶ 61,210 (2003).

terms and conditions necessary to implement a Day-Ahead Energy Market, Real-Time Energy Market, and FTRs. The July 25 Filing met with numerous protests, many of which alleged that the filing was incomplete and premature. Following a stakeholder vote, the Midwest ISO filed a motion to withdraw the proposed TEMT, but it requested "any and all guidance the Commission can give the Midwest ISO and its stakeholders on the matters presented in the July 25th Filing."[16]

14. The Commission granted the Midwest ISO's motion to withdraw the July 25 Filing and provided, on an advisory basis, guidance on a number of issues raised in that filing.[17] The Commission stated in the TEMT I Order that it expected its guidance to better enable the Midwest ISO to prepare and file a complete version of the TEMT or a similar proposal. The Commission instructed the Midwest ISO to include five elements in its revised Energy Markets filing: (1) a *pro forma* System Support Resource Agreement; (2) a marginal loss crediting mechanism; (3) a methodology for initial FTR allocations; (4) creditworthiness provisions; and (5) market mitigation measures.

15. The Midwest ISO filed a revised TEMT on March 31, 2004 (March 31 Filing), raising an issue that will be important to the operation of the proposed Energy Markets. The Midwest ISO stated in its transmittal letter, and through the testimony of two witnesses, that it would be unable to operate its Energy Markets without integrating an estimated 300 pre-OATT GFAs that are currently effective in the Midwest ISO region. It also concluded that up to 40,000 megawatts of transmission service – about 40 percent of total load in the region[18] – is likely to be associated with the GFAs.[19] The Midwest ISO

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[16] Motion to Withdraw Without Prejudice the July 25 Energy Markets Tariff Filing at 5, Docket No. ER03-1118-000 (Oct. 17, 2003).

[17] Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,145 (2003) (TEMT I Order), *reh'g dismissed*, 105 FERC ¶ 61,272 (2003).

[18] The Midwest ISO stated that, after reviewing all of the contracts listed in Attachment P of the OATT, the specific details of the contracts, such as usage, scheduling requirements and megawatt quantity or capacity, were not readily apparent on the face of some of the contracts. The Midwest ISO added, however, that about half the contracts had a specific megawatt value associated with them, and that in the aggregate those contracts accounted for approximately 20,000 megawatts of capacity. The Midwest ISO projected that the remaining half of the GFAs were likely to be associated with a similar number of megawatts.

[19] The Midwest ISO's analysis assumed a peak capacity of 97,000 megawatts. *See* Dr. Ronald D. McNamara, Vice President of Regulatory Affairs and Chief Economist of (continued)

argued that allowing holders of GFAs scheduling rights similar to their current practice would require a physical reservation, or carve-out, of transmission capacity in the Day-Ahead Energy Market and until the scheduling deadline prior to real-time dispatch. It stated that this "cannot be accomplished without negatively impacting the Midwest ISO's ability to reliably operate the Energy Markets and without placing excessive financial burden on other Market Participants."[20]

16. The Procedural Order gave an initial response to the threshold GFA issue. The Commission explained that "the development of the Midwest ISO as an RTO has reached a point at which the Commission must examine the potential conflict between our desire to preserve the GFAs and our instructions that the Midwest ISO should develop a market-based system of congestion management."[21] The Commission identified a need for further information about the GFAs and a desire to better understand how the GFAs and the proposed Energy Markets would affect one another. Accordingly, the Commission initiated an investigation, under section 206 of the FPA, of the GFAs "to decide whether GFA operations can be coordinated with energy market operations, whether and to what extent the [Transmission Owners] should bear the costs of taking service to fulfill the existing contracts and whether and to what extent the GFAs should be modified."[22]

17. As described below, the Commission ordered GFA parties to file interpretations of their contracts in Stage 1 of the investigation, and established trial-type hearing procedures, before administrative law judges (presiding judges) – Stage 2 of the investigation – to elicit the GFA information from those parties who were not able to agree in Stage 1. The Commission also offered GFA holders an opportunity to settle their GFAs by voluntarily accepting the GFA treatment that the Midwest ISO proposed in the TEMT.

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the Midwest ISO, testimony at 84 n.5.

[20] March 31 Filing at 9.

[21] Procedural Order at P 65. *See also* Declaratory Order at P 29-32, 64 ("We continue to believe that customers under existing contracts, both real or implicit, should continue to receive the same level and quality of service under a standard market design."); Declaratory Order Rehearing at P 27-31; *cf.* TEMT I Order at P 22 (encouraging the Midwest ISO to resubmit its Energy Markets proposal).

[22] Procedural Order at P 67.

18. Stage 2 of the Commission's investigation of the GFAs concluded on July 28, 2004, with the presiding judges' oral presentation to the Commission of the results of the hearing they held to elicit GFA information that was outstanding after Stage 1 and the issuance of their written Findings of Fact.[23] As outlined in the Procedural Order (and below), the instant order considers all the evidence developed in Stages 1 and 2 of the section 206 investigation to decide how GFAs should be treated in the Midwest ISO's Energy Markets.[24]

19. Finally, on August 6, 2004, the Commission issued an order approving the Midwest ISO's proposal.[25] The Commission accepted and suspended the proposed TEMT and permitted it to become effective March 1, 2005, subject to conditions and further orders on GFAs and Schedules 16 and 17 of the Midwest ISO Tariff.[26] The Commission also accepted certain tariff sheets to be effective on August 6, 2004, subject to conditions and further order on GFAs. In order to address the Midwest ISO's unique features, such as the fact that it does not have prior experience operating as a single power pool and has only a short period of experience operating under a single reliability framework, the Commission ordered the Midwest ISO to implement additional safeguards to ensure additional confidence-building protections for wholesale customers during startup and transition to fully-functioning Day 2 Energy Markets in 2005.

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[23] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 63,013 (2004) (Findings of Fact).

[24] *Id.* at P 78.

[25] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,163 (2004) (TEMT II Order).

[26] Schedule 16 provides for a deferral of costs related to the development and implementation of the system and processes required to administer FTRs and the recovery of those deferred costs and the costs related to the ongoing administration of FTRs. Schedule 17 provides for a deferral of start-up costs related to the establishment of energy markets and recovery of such deferred costs and the ongoing costs of providing Energy Markets Service once the markets are operational.

II. Discussion

A. Procedural Matters

20. Parties filed numerous comments in multiple stages in this proceeding regarding the Midwest ISO's proposed TEMT. The comments relevant to this stage of the proceeding are listed in Appendix A to this order. First, parties filed interventions, comments, and protests responding to the Midwest ISO's March 31 Filing on or before May 7, 2004 (May Comments). Second, on or before June 25, 2004, parties filed comments in response to paragraph 74 of the Procedural Order regarding the effects of GFAs in the Midwest ISO's Energy Markets (June Comments). Third, on or before July 16, 2004, parties filed comments responding to the June Comments (Reply Comments). Fourth, on or before July 16, 2004, parties filed comments responding to the Midwest ISO's and its Independent Market Monitor's (IMM), Potomac Economics, economic and reliability analysis (Analysis Comments).[27] Finally, parties filed briefs on exceptions to the presiding judges' Findings of Fact on August 17, 2004.[28]

B. Economic and Reliability Analysis

21. To assist the Commission in determining whether to modify GFAs that were not settled, we directed the Midwest ISO to provide evidence on three related issues, by June 25, 2004, concerning the reliability and economic benefits of the Midwest ISO's congestion management system with GFAs included in the market.[29] First, the Commission directed the Midwest ISO and its IMM, Potomac Economics, to submit evidence of the historical reliability impact of North American Electric Reliability

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[27] As discussed below, the Procedural Order instructed the Midwest ISO and its IMM to file economic and reliability analysis of GFAs in the market by June 25, 2004. Procedural Order at P 72-73.

[28] On August 20, 2004, Consumers filed a brief opposing Detroit Edison's exceptions. Per the Procedural Order, which stated that "[b]riefs opposing exceptions will not be allowed," we will not accept Consumers' brief opposing exceptions. *See* Procedural Order at P 76. In addition, on September 7, 2004, Detroit Edison filed a motion to reject Consumers' brief opposing exceptions and, in the alternative, a response to Consumers' brief. In light of our rejection of Consumers' brief opposing exceptions, we will also reject Detroit Edison's response.

[29] *Id.* at P 72.

Council (NERC) Transmission Line-Loading Relief (TLR)[30] procedures in the Midwest ISO region. Second, the Commission directed the Midwest ISO to submit evidence that examines in detail how a carve-out of the GFAs would impede the reliability of the proposed Day 2 Energy Markets.[31] Third, the Commission directed the Midwest ISO to file information on the economic impacts of TLRs in its region and the quantifiable benefits of the proposed congestion management system, focusing on how a carve-out of the GFAs would impede these costs savings.[32] Parties were given an opportunity to comment on the Midwest ISO's analysis.[33]

22. The Commission also sought comments from all affected parties on: (1) whether keeping the GFAs separate from the market would negatively impact reliability; (2) the extent to which accommodating GFAs would shift costs to third parties; and (3) whether keeping the GFAs separate from the market would result in undue discrimination. Parties were given an opportunity to submit reply comments.[34]

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[30] According to NERC TLR procedures, in the event that curtailments are required to reduce power flows on constrained flowgates below operation security limits, the transmission operator cuts all transactions that impact the constrained flowgate by more than the five percent threshold in order of the relevant service priorities. Within each service priority, transactions with impacts above the 5 percent threshold are curtailed on a pro-rata basis. The nature of power systems is such that operators cannot curtail only the portion of the power flow from each transaction that affects the constrained flowgate; rather, the entire transaction must be curtailed.

[31] Procedural Order at 72.

[32] *Id.* at P 73. The Commission directed the Midwest ISO to include all workpapers and assumptions supporting its quantification of the economic benefits of the proposed congestion management system as it applied to the GFAs.

[33] By notice issued June 18, 2004, the Commission allowed initial comments to be filed on July 16, 2004.

[34] By notice issued June 18, 2004, the Commission allowed reply comments regarding the three issues enumerated above to be filed on July 16, 2004.

1. Midwest ISO and IMM Data and Analysis

23. On June 25, 2004, the Midwest ISO submitted testimony in its Compliance Filing[35] to the Commission on the reliability and economic impacts of the Midwest ISO's congestion management system with and without accommodation of GFAs in their current form and the IMM submitted an analysis of TLR procedures. The Midwest ISO estimated a $713.1 million annual benefit from congestion management, or $586.1 million net of energy market costs.

24. In its Compliance Filing, the Midwest ISO explains that, of the contracts it reviewed, approximately half had a specific megawatt value associated with the contract. These contracts in the aggregate accounted for approximately 20,000 MW of capacity.[36] Based on this analysis, the Midwest ISO estimates a total of 40,000 MW associated with all of the GFAs, as noted in the Procedural Order.[37] With respect to reliability impacts, the Midwest ISO makes several points predicated upon the estimated 40,000 MW cutout. First, according to Dr. McNamara, a physical carve-out from the actual dispatch is not possible. He asserts that it is physically impossible to ignore or treat separately the electrical energy associated with GFAs (or any other bilateral contract) when arranging dispatch and coordinating real-time power flows.

25. Second, Dr. McNamara explains that allowing a carve-out from the scheduling timelines in the TEMT for GFAs impacts reliability. To the extent that the GFAs allow for more flexibility in the scheduling than is allowed in the TEMT, the Midwest ISO will have to estimate the generation and load from the GFAs in order to commit sufficient units to ensure reliability. Without direct GFA scheduling data, these estimates will invariably be less accurate than the information the GFA parties themselves would be capable of providing under the TEMT.

26. Third, Dr. McNamara states that the introduction of a regional security-constrained economic dispatch (SCED) will improve reliability in the Midwest ISO footprint. Changing from local control area dispatch in conjunction with TLR procedures to regionalized 5-minute dispatch will lead to more precise management of transmission

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[35] Midwest ISO June 25, 2004 Compliance Filing at 2. Analysis of Summary Results addressed in the testimony of Dr. Ronald D. McNamara, Vice President of Regulatory Affairs and Chief Economist.

[36] *See* McNamara testimony at 61.

[37] Procedural Order at P 16.

constraints and will improve the reliability of the network. A carve-out for GFAs would undermine both reliability and economic benefits by removing incentives for GFA parties to schedule efficiently and participate in a regional SCED.

27. To provide background, Dr. McNamara explains that, under current operations, the Midwest ISO, in its role as Reliability Coordinator, does not dispatch generation. The existing method for managing congestion relies on reserving and scheduling estimated Available Flowgate Capacity (AFC) and, when not all scheduled service requests can be physically accommodated, curtailing transmission service under TLR procedures - in essence, physically rationing transmission capacity based on priorities related to firmness and length of service with economic redispatch of intra-control area transactions being performed by each of many small control areas. Like other physical rationing mechanisms, according to Dr. McNamara, the current approach contains inherent inefficiencies due to under-utilization of assets and the inability to optimize asset utilization based on prices and economic value.[38]

28. Current system operations, states Dr. McNamara, will be replaced with a process in which much of system operations and the all-important function of generation dispatch and related reliability functions will be performed or coordinated at the regional level by the Midwest ISO under the TEMT. According to Dr. McNamara, the Midwest ISO is now functioning as Reliability Coordinator for its footprint and has already assumed some regional coordination functions associated with reliability, which include operating the Midwest ISO Open-Access Same-Time Information System (OASIS) and processing requests for transmission reservations, scheduling inter-control area transactions, and managing use of the TLR curtailment process for congestion that is not managed by local area dispatches. However, asserts Dr. McNamara, some of these current responsibilities will change somewhat under the proposed TEMT, wherein the Midwest ISO will assume responsibility for operating a regional SCED (which will replace TLRs) to relieve congestion.[39]

29. Dr. McNamara analyzes the effect of replacing TLRs with a regional SCED to relieve congestion and concludes that a SCED system will be a substantial improvement in the overall reliability of the grid. However, for this improvement to occur, Dr. McNamara explains that the security-constrained economic dispatch must be coordinated

[38] *See* McNamara testimony at 48.

[39] *Id.* at 5 and 6.

at the regional level, not the local control area level, to capture the fact that loop flows are a broad regional phenomenon, not just a local issue.[40]

30. Dr. McNamara states that reliance on TLRs for congestion management inherently leaves transmission capacity under-utilized because the TLR approach relies on imprecise flow estimates and cannot accurately reflect system interactions. Further, explains Dr. McNamara, the Reliability Coordinator calling the TLRs cannot know how long each of the scheduling parties will take to implement the requested curtailments. The amount of congestion relief achievable from the TLR approach, according to Dr. McNamara, is therefore imprecise and somewhat unpredictable. He states that the Regional Reliability Coordinator that calls the TLR cannot accurately predict how much relief the constrained grid will realize through each TLR curtailment, and therefore may curtail too many or too few transactions in each TLR event.

31. Moreover, he explains, TLRs are issued to curtail specific transmission transactions. When a transaction is curtailed, the affected control areas must then redispatch generation, curtail load or reconfigure their systems to comply and maintain balance. Each of these actions, according to Dr. McNamara, takes time and occurs within constantly changing levels and patterns of load, generation and power flows.

32. The Midwest ISO's analysis of TLR events in its region during 2003 found that reliance on TLRs for congestion management makes it more difficult to maintain power flows within operating security limits. Actual or post-contingency power flows violated security limits at some point in 556 of the 926 TLR events studied. The total time spent in violation of the security limits equaled 2,163 out of the total of 10,820 hours or 20 percent of the duration of the 926 TLRs studied. While most of the excursions above the security limits were for limited periods and within the emergency limits of the affected transmission facilities, the fact that they occurred at all reflects the inherent difficulty in relying on TLRs to protect system reliability.[41]

33. The IMM also analyzed the impact of TLRs, and agreed with the Midwest ISO that there are significant uncertainties in the TLR process. The IMM states these uncertainties can affect reliability and the system operators' ability to fully utilize the system. Because of these uncertainties, conservative assumptions must be used to

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[40] *Id.* at 8-10.

[41] *Id.* at 44-45.

schedule transmission service and operate the system. Even operating the system in a conservative manner, explains the IMM, there are still periods when the flows exceed the operating limits because the TLRs invoked do not provide the full amount of relief anticipated for the transmission constraint. According to the IMM, the central dispatch that occurs in an LMP market increases the RTO's control over network flows. When flows do approach the limit, the LMP market will quickly and effectively redispatch generation to prevent the flows from exceeding the limit. It is the opinion of the IMM that the uncertainties and imprecision that are inherent in the current TLR regime result in the Midwest ISO having less control of the network flows. When these flows exceed the operating security limits for a transmission facility or flowgate, one may conclude that the TLR procedures have contributed to a lower level of reliability than would exist under the proposed LMP markets, states the IMM.

34. The IMM conducted an analysis of TLR events in the Midwest ISO in calendar-year 2003 that showed that 39 percent of the TLR curtailments are accurate, with over-curtailments or under-curtailments of less than 1 percent of the flowgate limit. These results, states the IMM, are encouraging considering the uncertainties inherent in the TLR processs. However, in the opinion of the IMM, reliability concerns associated with the TLR process are raised by the instances of under-curtailments when the flow is greater than the flowgate limit by more than 1 percent. The IMM's analysis shows that this occurred in 16 percent of the hours when TLRs were invoked. The IMM contends that implementation of centralized dispatch would eliminate these instances as generation is redispatched continuously to maintain network flows at or below the transmission limits.

35. To answer the second question in the Procedural Order (evidence that examines in detail how a carve-out of the GFAs would impede the reliability of the proposed Day 2 markets), Dr. McNamara begins by defining the term "carve-out." According to Dr. McNamara, the Procedural Order sometimes spoke of a "carve-out from the market" and other times indicates that the carve-out has something to do with physical scheduling requirements. However, because dispatch and use of the real-time market are the same thing, explains Dr. McNamara, it is not meaningful to consider concepts that assume that GFA schedules could be handled "outside the market." Dr. McNamara states that because all schedules, all injections and all withdrawals are using exactly the same grid, *all* schedules and grid uses affect flows on the grid and all schedules must be accounted for in the system operator's security-constrained economic dispatch. He states that the flows from all schedules and grid uses determine the degree and location of congestion and thus affect the need for, and the costs of, congestion redispatch. Hence, according to Dr. McNamara, there is no meaningful way in which GFA schedules can be carved-out without affecting the market and the market prices faced by third parties. In this sense, he concludes, the very concept of a carve-out is problematic.

36. Furthermore, Dr. McNamara considers the notion of a "physical" carve-out to be incompatible with the requirements for a reliable dispatch. Dr. McNamara cites to Dr. Hogan's March 31, 2004 testimony discussing GFA treatment, in which Dr. Hogan made clear that a total physical carve-out of all possible grid usages that could occur under the many GFAs is simply not workable. Dr. Hogan emphasized, and the Commission noted in its Procedural Order, that the grid operator must know the net injections and net withdrawals, by location, of each grid usage, in order to arrange a security-constrained economic dispatch. Dr. Hogan noted that this information is, of necessity, today provided to the local entities responsible for grid operations and so must be provided to the Midwest ISO when it takes over the same grid operation functions, such as a regional security-constrained economic dispatch. Dr. Hogan concluded that all grid users, including parties to GFA transactions, must provide to the Midwest ISO the same information on each schedule's net injections and net withdrawals and must do so within the same time deadlines that apply to all proposed grid usage.

37. Assuming that the definition of "carve-out" means that GFA schedules could be exempt from these most basic requirements for maintaining reliable operations, Dr. McNamara explains that the Midwest ISO would have to accommodate GFA schedules no matter when they were submitted, no matter what the net injections or net withdrawals were and no matter what locations were affected, up to the limits defined in the GFAs.

38. Further, according to Dr. McNamara, carving out GFAs in this way would mean that GFA parties would not participate in any way in five major enhancements the Midwest ISO is bringing to the region in the TEMT. The first enhancement he lists includes a regional security-constrained economic dispatch, and the availability of this dispatch to replace the use of TLRs. Dr. McNamara states that a carve-out could mean that GFA schedules would need to be subject to the same degree of TLRs as they are now, and that the Midwest ISO would not offer or provide redispatch to support GFA schedules if they would otherwise have been subject to TLRs. Nor, Dr. McNamara posits, would GFA parties be allowed to purchase and pay for this redispatch service, even if redispatch was available and more economic than TLRs. The Midwest ISO would instead impose TLRs on the GFA schedules to the extent TLRs would have been used in the absence of the ISO's regional dispatch.

39. A second enhancement that Dr. McNamara lists is the ability to use the real-time balancing market to provide and price imbalances and to buy and sell energy. GFA parties would, instead, according to Dr. McNamara, obtain balancing service from the local control areas under the restrictions and penalties that apply today. Dr. McNamara states that other enhancements that GFAs would be unable to use include: the ability to use the day-ahead energy market to lock-in energy and transmission prices in advance; the use of LMP prices for imbalances and spot market sales and purchases, and the use of

LMP-based usage charges to price transmission usage and congestion redispatch; and, the ability to be compensated for counterflows that help relieve congestion.

40. If, according to Dr. McNamara, it is assumed that a carve-out means that the GFA schedules were not subject to the same scheduling deadlines and net injection and withdrawal data requirements as other grid users, and not subject to LMP-based energy and usage charges in either the day-ahead or real-time markets, then the Midwest ISO would still need to account for the capacity likely to be used by GFA schedules when they were finally submitted. In the day-ahead energy market, according to Dr. McNamara, assuming GFA schedules would not be submitted by the day-ahead scheduling deadline, the Midwest ISO would be required to make its own estimates of GFA schedules. Because GFA schedules would not be subject to the LMP price signals that encourage behavior consistent with reliability, there would be no incentives for GFA parties to take actions consistent with reliable dispatch – there would be no incentive for the GFA parties to participate in the day-ahead market, so the Midwest ISO could not get any advance indication on how the grid would be used in real time other than its own guesses of expected GFA transmission usage.

41. In response to the Procedural Order, the Midwest ISO performed this analysis at congested flowgates during 2003 in three areas: (1) the Mid-Continent Area Power Pool (MAPP) footprint; (2) the Wisconsin Upper Michigan System (WUMS) sub-region; and, (3) the rest of the Midwest ISO. The study found the under-utilization of transmission capacity during Level 3 and higher TLR events averaged 16.4 percent in the MAPP footprint, 10.9 percent in the WUMS sub-region, and 7.7 percent in the remainder of the Midwest ISO for 2003. The average unused capacity for the entire Midwest ISO region during all TLR events studied was 12.9 percent. In short, the study found that the grid was persistently under-used because of the imprecision and uncertainty of the TLR approach.

42. Accordingly, Dr. McNamara concludes that reliance on TLRs results in economic inefficiency. Under NERC TLR procedures, he states, when a curtailment is needed, all transactions in the selected service priority (gradations of firm and non-firm service) that impact the constrained flowgate by more than the minimum (5 percent) threshold are cut on a *pro-rata* basis. However, Dr. McNamara points out, the economic value of the curtailed transactions never enters into the *pro-rata* allocation of TLR curtailments. Moreover, he contends, as redispatch is neither offered nor priced, there is no mechanism by which the parties that are subject to TLR curtailments can determine whether it would be more economic to pay for redispatch in lieu of curtailment or to accept curtailment.

43. In the absence of a real-time price signal, explains Dr. McNamara, it is not possible to determine the economic impact of curtailing any particular transaction, nor is it possible to compare the marginal cost of redispatching generation to the economic

value of the transactions that are curtailed by TLRs. Thus, he concludes, it will often be the case that the costs of implementing a TLR greatly exceed the cost of a comparatively small economic redispatch that could provide the same reduction in flows over the constrained flowgate. For these reasons, Dr. McNamara believes that it is highly unlikely that the grid can be efficiently used under a TLR approach.[42]

44. The IMM agrees that TLR procedures are inefficient because they make no attempt to optimize the curtailments (*i.e.*, to redispatch the generation with the largest effect on the flowgate at least cost). In addition, states the IMM, the TLR curtailments themselves are subject to limited resolution in both time (they are essentially hourly) and space (transaction source and sinks are modeled at the control area level versus node or bus). With regard to the timing of the TLR calls, Reliability Coordinators are required to make decisions on TLR curtailments based on a combination of real-time information, forecasts of future flows, and the inherent lags in the participant's actions (including the permitted lag on the ramping of curtailed transactions), according to the IMM.

45. In contrast, according to Dr. McNamara, the proposed TEMT will provide for more efficient congestion management. Dr. McNamara considers a primary objective of the TEMT to be reliable, economic, and nondiscriminatory unit commitment and dispatch to efficiently manage transmission congestion. Once the dispatch is arranged, he argues, the proven way to encourage generators to follow dispatch instructions is through the use of LMP. Dr. McNamara posits that the proposed real-time and day-ahead energy markets are the means to secure price bids to facilitate coordinated unit commitment and security-constrained economic dispatch.

46. To evaluate these conclusions, the Midwest ISO conducted an analysis of the economic impact of TLRs and the benefits of the congestion management system reflected in the proposed TEMT. According to Dr. McNamara, the analysis determined the net economic benefits from the perspective of the cost of power at market prices moving from the current system of rationing transmission capacity and TLRs to the proposed system of congestion management. Looking at the cost of power at market prices, states Dr. McNamara, Midwest ISO members are likely to realize net economic benefits from implementation of the proposed TEMT of approximately $586.1 million per year. This reflects $713.1 million per year in savings from lower market prices for power in the Midwest ISO region. To calculate the net savings, explains Dr. McNamara, the amount of the benefit was offset by $127.0 million per year in fees to cover the implementation and operation of the proposed markets. The average load zone market-clearing price of power in the Midwest ISO footprint is forecast to be lower under the

[42] *Id.* at 12-15.

Midwest ISO TEMT by $1.18 per MWH. On a monthly basis, average price per MWH savings range from $0.46 in April to $1.94 for July. As explained by Dr. McNamara, the reduction in the load-weighted average market price was multiplied by Midwest ISO load to calculate the reduction in the market cost of power given the improved efficiencies from the proposed system of congestion management.

47. Dr. McNamara explains that the analysis also determined the net economic benefits, from a cost-of-service perspective, of moving from the current system of rationing transmission capacity and TLRs to the proposed system of congestion management. From a cost-of-service perspective, Midwest ISO members are likely to realize net economic benefits from implementation of the proposed TEMT of approximately $128.4 million per year, according to Dr. McNamara. This reflects $255.3 million per year in net savings from reduced generation and purchased power costs and increased revenues from off-system sales to parties outside the Midwest ISO footprint. This amount is offset by an estimated $127.0 million per year in fees to cover the implementation and operation of the proposed markets. Looking at the overall Midwest ISO footprint from a cost of service perspective, states Dr. McNamara, the savings are largely the result of lower prices for purchased power and an increase in both power imports to and exports from, Midwest ISO member companies. Total power purchases by Midwest ISO member companies from non-Midwest ISO generators are estimated to increase in the proposed market by 4.9 million MWH per year under the proposed TEMT. However, according to Dr. McNamara, despite the increased imports, coordinated unit commitment and dispatch can be expected to reduce market-clearing prices such that the average price paid for power imports would fall by an average of $2.74 per MWH, or 9.1 percent. The reduction in market clearing prices for such purchases is forecasted to result in a savings of $98.7 million per year, offsetting most of the impact of an increase in the volume of purchases. Additionally, power sales from Midwest ISO to non-Midwest ISO entities are expected to increase by 10.8 million MWH per year given the proposed Midwest ISO energy markets. The increase in revenues from sales to entities outside of the Midwest ISO of $282 million per year, less the cost of increased power purchases from others, (which, given lower prices in the Midwest ISO, equals $36.4 million), results in a net benefit to Midwest ISO members from off-system sales and purchases of $245.6 million per year, according to the study results.

48. Additionally, explains Dr. McNamara, total generation costs in the region are forecasted to decline by $9.7 million per year given the proposed system of congestion management. This is a calculation of net savings after taking into consideration the cost of generating an additional 5.8 million MWH for export.

49. The IMM also conducted an analysis to determine the benefits of the system for congestion management under the proposed TEMT compared to the current regime based

on TLRs. The likely differences in the outcomes of the TLR procedures versus the economic dispatch process resulting from an LMP market was evaluated by the IMM through a comparison of the results of the TLR process to a simulated redispatch of generation to manage the same congestion. This analysis, for the 2003 period, showed that the TLR process, on average, curtails more than three times more megawatts than would be necessary to achieve the same result through economic dispatch. It also shows that for individual flowgates, the TLR curtailments ranged from 73 percent more than the redispatch amount to 472 percent more (almost six times the redispatch amount).

50. With respect to the economic impacts of carving-out GFAs, Dr. McNamara notes that when the carved-out GFA schedules are finally submitted closer to real time, real-time congestion would likely be greater and the Midwest ISO would incur greater congestion redispatch costs in the real-time dispatch. Because the carved-out GFA schedules would not have to pay the marginal costs of redispatch for congestion imposed by their own schedules, the GFA parties would not have any incentives to schedule efficiently or to choose wisely between alternative generation that might limit redispatch costs. In contrast, non-GFA parties who deviate from their day-ahead schedules would have to pay these increased congestion costs. In addition, while non-GFA parties who had followed their day-ahead schedules in real time would, under the proposed TEMT, not have to pay for increased congestion in the real-time market for their own transmission schedules, because they would already have purchased transmission for those schedules at day-ahead usage prices, they would still be exposed to the unhedgeable risks of real-time congestion costs because non-GFA parties, not the carved-out GFA parties, would have to pay the uplift for the unrecovered costs of congestion redispatch required in real time. Thus, this carve-out would result in additional costs for third parties.

51. To assess the economic impact of a GFA carve-out, the Midwest ISO developed an illustrative case using Power World's Simulator Optimal Power Flow model applied to Wisconsin and the surrounding control areas. The model is a power flow analysis tool that automatically identifies economically optimal redispatch in response to transmission constraints. It also calculates LMPs associated with that dispatch. In this case, the Midwest ISO simulated economically optimal power flows and calculated the resulting prices with and without a physical carve-out for known GFA reservations. To represent a physical carve-out, the Midwest ISO constructed the model to simulate what would happen if GFAs were scheduled as they always have, without taking advantage of more economic dispatch solutions through the Midwest ISO's proposed markets. The results showed significant observed differences in average load zone prices for the July peak hour for which the model simulated physically accommodating known GFA reservations. The inclusion of a physical representation of known GFA reservations in the model increased transmission congestion and average prices in the Wisconsin Public Service

load zone by 52.1 percent, from $143.60 to $218.35 per MWH; for Wisconsin Power and Light by 20.9 percent, from $133.15 to $161.02 per MWH; for Upper Peninsula Power by 11.2 percent, from $138.65 to $154.18 per MWH; and for WE Energies by 5.1 percent, from $133.86 to $140.73 per MWH.

52. According to Dr. McNamara, the illustrative findings strongly suggest that carving out GFAs in a manner that avoids exposure of the GFA parties to the economic benefits of regional economic dispatch and LMP's efficient price incentives could significantly raise peak hour prices (and probably non-peak prices as well) for all parties in the region. The impact of these higher prices, he states, would be felt by both non-GFA and GFA parties alike. Non-GFA parties, Dr. McNamara concludes, could face higher LMPs and possibly higher LMP-based transmission usage charges because with less generation available for dispatch, the marginal cost of redispatch would be higher than it would be with more generators participating. Dr. McNamara also notes that the findings suggest that a carve-out would force GFA suppliers to incur higher costs in meeting their load obligations than they would incur if they participated in the regional dispatch. These higher costs, explains Dr. McNamara, represent lost opportunity costs to the suppliers and potentially lost opportunity costs to the GFA loads to the extent their contracts allowed them to capture some of the potential savings.

53. Dr. McNamara also explains that, given the difficulty that the Midwest ISO may have in anticipating post-day ahead scheduling by GFA holders, a physical carve-out, in which GFA holders are not required to schedule their transactions in advance or pay imbalance charges, has the potential to create a significant artificial divergence between day-ahead and real-time prices. Consistent and significant price divergence has the potential to undermine the value of the day-ahead market.[43]

54. Finally, with respect to implementation impacts, Dr. McNamara states that it is unlikely that the Midwest ISO would be able to implement a physical carve-out in time to meet the Commission's March 1, 2005 schedule for the start of the Day 2 market. Dr. McNamara states that while it is not well understood what a physical carve-out would require, he does not believe that the Midwest ISO has enough time built into the implementation schedule to make business process and system changes to accommodate this option. Moreover, explains Dr. McNamara, even with unlimited time and expenditures, it is not clear whether the resulting market could function in a reasonable manner given the magnitude of the carve-out that might be required.[44]

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[43] McNamara testimony at 65-70.

[44] *Id.* at 65.

2. Parties' Comments on Economic and Reliability Analysis

(a) Comments in Response to the Midwest ISO and IMM's Evidence and Analysis

55. On July 16, 2004, the Michigan/Kentucky Parties, LG&E, Detroit Edison, the Midwest ISO TOs, the Midwest TDUs, and the Rural Electric Cooperatives filed comments on the Midwest ISO and IMM's reliability and economic impacts analysis.[45]

56. The Michigan/Kentucky Parties comment that the Commission should establish hearing procedures, subjecting the Midwest ISO's and IMM's analysis to cross-examination, because allowing parties only the opportunity to comment does not fulfill the Commission's constitutional due process obligation. They also urge the Commission to consider the ramifications of proceeding on the basis of the untested, uncorroborated assertions of the Midwest ISO. With respect to the IMM's analysis, the Michigan/Kentucky Parties assert that, to the extent the analysis relies upon presumed LMP market operations, it lacks a sound evidentiary basis because, at this point, the proposed LMP-based congestion management system has not yet been implemented and the design is incomplete. They state that, in its analysis, the IMM even admits that it has not conducted studies of TLRs and reliability "per se." The Michigan/Kentucky Parties assert that, rather than conducting a study of TLRs and reliability, the IMM's analysis consists of a comparison of historical TLR calls and the presumed impact of a "simulated" redispatch of generation under LMP, and that is a baseless assertion.

57. The Michigan/Kentucky Parties also claim that the Midwest ISO's analysis failed to quantify the benefits of its proposed congestion management system and to adequately analyze the impact of GFAs on the proposed market. Specifically, they argue that the Midwest ISO's analysis is flawed because it failed to provide workpapers, account for GFA rights, and quantify the impact of alleged GFA interference and cost shifts. They state that the Midwest ISO incorrectly presumes all GFAs' present scheduling limitations and ignores that any potential scheduling limitations can be overcome without abrogating or modifying GFAs. The Michigan/Kentucky Parties point out that, rather than figuring out a way to make a carve-out approach work, the Midwest ISO simply states that it does not have the time to build such an exercise into its schedule. Finally, the Michigan/Kentucky Parties argue that the Midwest ISO incorrectly and unfairly tags GFAs as the root of all congestion problems.

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[45] As stated above, Appendix A to this order lists the various parties who filed comments in this proceeding.

58. The Midwest ISO TOs also raise several concerns regarding the Midwest ISO's analysis stating that they do not accept the Midwest ISO's studies as to the costs associated with carving out GFAs and arguing that there has not been enough time to evaluate the reasonableness of the study. As to the Midwest ISO's TLR study, the Midwest ISO TOs argue that it would be necessary to test all of the assumptions and models used to determine whether or not the results are valid and that has not been, and cannot be, done without the opportunity for discovery concerning the model and data used by Dr. McNamara. The Midwest ISO TOs also point to their June Comments, where they proposed to provide GFA parties with two additional alternatives, stating that nothing filed by the Midwest ISO affects the validity of their proposed alternatives.

59. Detroit Edison also submitted comments in response to the Midwest ISO's analysis, requesting that the Commission require the Midwest ISO to complete a more thorough analysis of any impacts that honoring GFAs may have on reliability. It states that the Midwest ISO's conclusions with regard to how a carve-out of GFAs would impede reliability of the proposed Day 2 markets are wholly unsupported and that the Midwest ISO fails to quantify the impacts of honoring GFAs. Detroit Edison also asserts that the Midwest ISO's primary concern is the time that it would take to determine whether honoring GFAs would impact reliability.

60. The Rural Electric Cooperatives contend that the Midwest ISO's estimate of the megawatt magnitude of the transmission services associated with the GFAs is speculative. Thus, they submit the testimony of Stephen P. Daniel, which they contend illustrates that the Midwest ISO overstates the current and future magnitude of the GFA issue and fails to support the need to abrogate GFAs. The Rural Electric Cooperatives also contend that the Midwest ISO's calculation regarding the benefits of implementing LMP is questionable because: (1) the estimate is a single-year snapshot that is not necessarily indicative of the future as conditions change; (2) the estimate is likely within the margin of error of the model used; (3) from the limited information presented, it appears that the model used by the Midwest ISO is more akin to a Midwest ISO regional economic dispatch model based on costs rather than a bid-based LMP market as proposed in the TEMT; and (4) since the Midwest ISO did not submit all of its workpapers and assumptions supporting its quantification of benefits, and given the tight constraints of this proceeding, it is impossible to fully verify or challenge the Midwest ISO's analysis.

61. With respect to reliability, the Rural Electric Cooperatives assert that the Midwest ISO's analysis of purported reliability impacts is based solely on economic theory related to increased grid utilization, and is not a factual, or even reliability-driven analysis. They explain that the debate of the merits of TLRs versus LMP is not germane to the GFA reliability impacts issue because TLRs will still be necessary, even in organized markets using LMP (as evidenced in PJM, New York, and New England), in order to maintain

reliability. Further, the Rural Electric Cooperatives assert that the information filed by the Midwest ISO's IMM does not relate to reliability, but to purported efficiencies that might be achieved by replacing TLRs with LMP markets, suppositions about increased utilization of the grid that LMP markets would allow as compared to TLRs, and unsupported allegations that central dispatch as utilized in an LMP market would increase the RTO's control over network flows.

62. The Midwest TDUs contend that the Midwest ISO's cost-benefit study suffers from at least seven fundamental flaws in that it: (1) is opaque, to the point of non-compliance (because the Midwest ISO did not submit all of its workpapers and assumptions supporting its quantification of benefits); (2) reflects, as vastly understated, the markets' cost because it only considers projected spending by the Midwest ISO itself; (3) ignores seams between the Midwest ISO and its neighbors in its treatment of flowgates; (4) unrealistically derates internal and external flowgates; (5) ignores the potential exercise of market power because it assumes that each generator will be bid and dispatched at its marginal cost; (6) lacks sufficient justification for the hurdle rates used in the analysis; and (7) fails to account for the fact that LMP-based markets impose costly risks on their participants.

63. Additionally, the Midwest TDUs argue that the Midwest ISO's other arguments for overriding GFAs, that do not focus on the cost-benefit calculus, also fail. They state that while the Midwest ISO argues that application of the TEMT to GFAs is needed to enable it to "see" the sources and sinks associated with intra-control-area GFA schedules, it is far from obvious that the Midwest ISO needs all of its proposed changes to GFA arrangements to accomplish such visibility. The Midwest TDUs also argue that the Midwest ISO can not disregard the Standard Market Design White Paper[46] commitment to protect the economics of both GFAs and other existing long-term firm transactions when it asserts that the three options it proposes for GFAs could increase costs to third parties as compared to eliminating GFA treatment.[47] Further, in response to the Midwest ISO and certain generator-oriented stakeholders' assertion that the Midwest ISO's options might hold GFA parties better than harmless and suggestion that those options should be curtailed, the Midwest TDUs state that any finding of unjust enrichment would be baseless.

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[46] Remedying Undue Discrimination through Open Access Transmission Service and Standard Market Design, Notice of White Paper, Docket No. RM01-12-000 (Apr. 28, 2003).

[47] *See* Midwest TDU's Analysis Comments at 12.

64. LG&E submitted a protest to the Midwest ISO's June 25 filing, asking the Commission to reject the Midwest ISO's analysis and, to the extent that the Commission accepts the filing, establish an evidentiary hearing to examine the economic and reliability benefits of the Day 2 market and the potential cost shifts associated with Options A, B, and C for GFA treatment. LG&E also argues that the Midwest ISO fails to justify its criticism of TLRs or its advancement of its congestion management proposal.

(b) June Comments Generally Supporting GFA Carve-Out

65. Pursuant to P 74 of the Procedural Order, on June 25, 2004, the parties listed in Appendix A to this order filed comments on the impact of accommodating GFAs in the market. Detroit Edison, Hoosier, the Michigan/Kentucky Parties, the Midwest ISO TOs, AECC, Corn Belt, Montana-Dakota, TVA, and the Rural Electric Cooperatives generally believe that exclusion of the GFAs from the Midwest ISO Energy Markets would not impact reliability, shift costs to third parties, or result in undue discrimination.

66. Specifically, Detroit Edison asserts that keeping the GFAs separate from the market would not negatively impact reliability, pointing out that other regions have honored GFAs without a noticeable impact on the reliable operation of the transmission system. For example, it argues that "phantom congestion" due to grandfathered agreements in the California ISO (CAISO) did not jeopardize the reliability of the CAISO's transmission system. Detroit Edison also comments that the Commission must balance any cost shift to third parties by recognizing the cost shift to GFA parties that will occur if they are forced to reform or abandon their previously approved contracts. Further, Detriot Edison comments that contracts that were previously approved by the Commission should not be deemed unduly discriminatory by virtue of an energy markets platform that the Commission has not fully explored and is in the process of refining.

67. According to the Michigan/Kentucky Parties, eradicating or reshaping GFAs to accommodate a market that does not exist and that has not been approved is contrary to established law. They state that the legal presumption is in favor of upholding the GFAs and that the Midwest ISO should bear the burden of establishing a *prima facie* case establishing GFA reliability concerns. They argue that the Commission should set the matter for hearing and investigation to afford interested parties their due process rights. The Michigan/Kentucky Parties explain that if the GFAs are incompatible with the market, then the market must be reshaped or rejected. They assert that the Commission and the Midwest ISO were aware of the GFAs prior to the Midwest ISO's formation, which would not exist unless the Midwest ISO Agreement, requiring the Midwest ISO to honor GFAs, came into effect. Further, the Michigan/Kentucky Parties state that reliability of the transmission grid does not hinge on the existence of GFAs alone and that inquiry into this factor will prove useless. They also note that GFAs do not shift costs to third parties because no third party is being asked to pay any portion of any payment due

from one party to another under any GFA. Finally, they argue that different treatment does not equate to undue discrimination.

68. The Midwest ISO TOs explain that there are no reliability or economic issues preventing a carve-out of the GFAs from the Midwest ISO markets, especially if the solution they propose is implemented. The Midwest ISO TOs assert that central to the compromise that led to the voluntary formation of the Midwest ISO was that the GFAs would not be disturbed during the six-year transition period and to break this understanding would hinder future development of RTOs and ISOs.

69. With regard to reliability, the Midwest ISO TOs state that while advance notice of system conditions aid a system operator's ability to manage reliability, the day-ahead market is a financial market and does not provide all of the necessary information required to ensure reliability in real time. They argue that reliability does not hinge on load scheduling in this market and that market participants are not even required to schedule load in the day-ahead market. With respect to cost shifting, the Midwest ISO TOs assert that based on prior Commission decisions, GFA loads are already subject to Schedule 10 charges under the Midwest ISO Tariff, which covers a large portion of Midwest ISO's infrastructure costs. The Midwest ISO TOs also contend that under well-established case precedent, the existence of differing rates, terms, and conditions due to the existence of contracts executed at different times has repeatedly been found by the courts not to constitute undue discrimination.

70. Hoosier comments that it is both a GFA customer and a GFA provider of service. As a GFA customer, Hoosier joins in the Midwest ISO TO's comments. In its role as a GFA service provider, Hoosier argues that because it is not a public utility under the FPA, it is not subject to the jurisdiction of the Commission and thus, the Commission cannot modify Hoosier's GFA contracts. Regardless, Hoosier states that the continued implementation of its GFAs will not negatively impact reliability, or result in cost shifting or undue discrimination. Hoosier explains that because its contracts will not contribute significantly to increased congestion, costs related to congestion management will not be diverted to third parties as a result of keeping its GFAs separate.

71. TVA comments that there would be no negative impact on reliability from keeping the two GFAs to which it is a party separate from the Midwest ISO market. TVA suggests that notifying the Midwest ISO of day-ahead projections and real-time use information would provide sufficient information to assist the Midwest ISO in assessing the capability and reliability of the system. TVA also asserts that forcing GFA transactions to participate in the market would be unduly discriminatory and would unfairly shift costs of running the Midwest ISO market from Midwest ISO members who regularly use those markets, to those GFA parties who need only transmission service under their GFAs.

72. Montana-Dakota states that maintenance of the GFAs to which Montana-Dakota is a party will not have a material adverse impact on implementation of the TEMT. It asserts that regardless of the manner in which the GFAs of other Midwest ISO participants might be treated, the Commission should respect its prior determination to accord special treatment to the GFAs to which Montana-Dakota is a party until February 1, 2008. Further, Montana-Dakota states that keeping GFAs separate from the market would not shift additional costs to third parties or result in undue discrimination; however, forcing GFAs into the market would.

73. Similarly, Corn Belt asserts that the contractual terms and physical rights set forth in its GFAs should be preserved and not modified to make Corn Belt an unwilling participant in the Midwest ISO's Energy Markets. It argues that keeping the GFAs separate will not result in cost shifts to third parties or undue discrimination because any capacity available for third parties is subject to a Commission-approved OATT. Corn Belt further notes the possible legal ramifications that may result if modifications to its existing contracts are considered in conjunction with its Rural Utilities Service loan contract.

74. Rural Electric Cooperatives do not believe that a separation of the GFAs from the Midwest ISO market will impact reliability or result in an inappropriate shift of costs to non-GFA holders. Rather, they contend that the costs identified by the Midwest ISO are a consequence of the structure proposed in the TEMT rather than costs originating with the GFAs. However, Rural Electric Cooperatives stress that in order to fully comment on these issues, any dispute regarding GFAs must be resolved via the hearing process, where a larger picture of the current state of GFAs will be provided.

75. AECC argues that market designs that do not accommodate GFAs could impede, rather than accelerate, progress toward competition in wholesale markets. AECC explains that it is not located in the Midwest ISO footprint and is not a party to any GFAs, but that the outcome of these proceedings could substantially affect its pre-Order No. 888[48] agreements. It reminds the Commission that the existing transmission grid was

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[48] Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs., Regulations Preambles January 1991 - June 1996 ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs., Regulations Preambles July 1996 - December 2000 ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Study Group, *et al.* v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New (continued)

designed to accommodate longstanding contract path-based arrangements, like GFAs. AECC believes that concerns about reliability can be attributed to newer, possibly beneficial, uses of the system and that it is reasonable for the Commission to ask the advocates of these new uses to accommodate the existing uses, rather than break existing contracts.

(c) June Comments Generally Opposed to a GFA Carve-Out and Other June Comments

76. Cinergy, Dynegy, and FirstEnergy generally believe that exempting GFAs from the Midwest ISO TEMT would negatively affect the Midwest ISO market, while OMS, LG&E, WPPI, WPS Resources, and the Midwest TDUs have mixed responses regarding the issue.

77. Specifically, Cinergy argues that carving out GFAs would undercut many of the reliability benefits associated with the Day 2 market as there would be greater complexities in the physical scheduling systems as well as different financial incentives for GFA and non-GFA parties. It states that exempting GFAs from the Midwest ISO TEMT would cause inefficiencies in both the energy spot market and the FTR market due to distortion of the incentives GFA transacting parties would otherwise encounter when considering participation in the Midwest ISO spot markets, resulting in sub-optimal region-wide unit commitment and dispatch. Cinergy comments that costs will be shifted to non-GFA parties who are subject to LMP and that a GFA carve-out approach would create two classes of transmission service on the shared grid, which would be unduly discriminatory.

78. Dynegy states that separating GFAs from the market will negatively affect reliability because the model used for day-ahead system security will be inaccurate. It states that in order to assure that the requisite voltage and flow are available, the Midwest ISO will have to make a conservative estimate, which will lead to the Midwest ISO using both the day-ahead and real-time Reliability Assessment Commitment to unnecessarily order on unneeded generating units. Further, it asserts that undue discrimination against non-GFA transactions will result if GFAs are carved-out, leading to an inefficient, inaccurate day-ahead dispatch with potential for under-use of system capability and preferential treatment for GFAs. Dynegy states that most entities will perform a cost/benefit analysis between joining PJM versus the Midwest ISO and that those with

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York v. FERC, 535 U.S. 1 (2002).

the ability to choose, should choose PJM for more (and more mature) markets and a known, consistent quantity/quality.

79. FirstEnergy submits that keeping the GFAs separate from the market may not negatively affect physical reliability, but will negatively affect the implementation of the Midwest ISO's proposed market-based congestion management procedure. It also states that costs will shift to third parties, but that the magnitude of these costs cannot be determined until uplift charges and FTR uses have been determined. It also asserts that keeping GFAs separate from the market will result in undue discrimination, because by allowing GFAs to participate in the Midwest ISO, customers would receive access to transmission service without paying the associated costs that all other market participants are required to pay. However, FirstEnergy states, maintaining the terms of GFAs while subjecting GFA transactions to the Energy Markets could result in Transmission Owners' incurring additional costs that they are unable to recover under the GFAs, unless the Commission reforms the GFAs.

80. WPPI contends that by separating GFAs from the market, market participants will be forced to pay uplifted congestion costs attributed to GFA transmission as well as Midwest ISO costs to administer these agreements. It argues that the TEMT would not provide long-term firm transmission customers the same protections from congestion pricing risk that it does GFAs, and hence it is discriminatory. In addition, WPPI asserts that the TEMT allows full FTR protection for some customers while denying it to others that will be subject to pro-rata reductions in the FTR allocation process even though both customer classes obtained their existing service through the same capacity reservation process. WPPI recommends that this discrimination be remedied by allowing long-term firm OATT reservations to be scheduled for physical delivery a day ahead under Option B or establishing a floor to limit FTR proration.

81. LG&E emphasizes that the proposed TEMT should be rejected and the Midwest ISO should file an amended Day 2 tariff comporting with the principles of voluntary market participation. It explains that if GFAs are carved out of the market, they will be provided greater scheduling flexibility, shifting costs to non-GFA loads. However, LG&E argues that keeping GFAs separate from the market may not necessarily impact reliability and that the Midwest ISO's continued ability to redispatch generation using the NERC TLR process will relieve any problematic constraints. LG&E states that there is no definitive evidence presented by the Midwest ISO, including Dr. Hogan's testimony that a carve-out of GFAs harms reliability. It also states that there is not enough information available to truly assess the reliability questions posed by the Procedural Order. It contends that the Midwest ISO should undertake a thorough and transparent analysis of the market impacts of GFA transactions.

82. OMS argues that separating GFAs from the Midwest ISO market will impact grid reliability if GFAs are not required to submit reasonably accurate schedules into the day-ahead market. However, if anticipated GFA use were scheduled in the day-ahead market with limited adjustments allowed in the real-time market, it would be feasible to keep GFAs separate. Nonetheless, OMS contends that GFA separation may result in undue discrimination in a variety of ways. For example, non-GFA holders will suffer discrimination due to less scheduling flexibility than GFA holders. Further, OMS states that the Midwest ISO's proposed accommodation of GFA congestion costs will result either in a shortfall of FTRs available for market participants to hedge their own congestion costs, or an uplift of congestion charges, and hence, an unfair shift of costs.

83. The Midwest TDUs contend that more information is needed before any reliability impact resulting from a GFA carve-out can be analyzed. However, they state that if it were proven that unpredictable GFA loads were locking up Midwest ISO paths, it might be appropriate to bring those GFAs into the market by encouraging or requiring day-ahead scheduling. They contend that the Midwest ISO's proposal will result in risk or cost shifting from the transmission provider, who under the GFA bears responsibility for late schedule changes, to the GFA customer, by forcing GFA transactions, to schedule sooner, bear losses differently, and pay for markets they do not use and taking from non-GFA existing transactions to the extent they do not get allocated full FTR hedges, the financial right to the energy they inject.

84. WPS Resources states that allowing the physical separation of GFAs could potentially impact grid reliability and result in unfair cost shifting. It states that allowing GFAs to participate in the Midwest ISO market, but forcing other participants to pay their costs, is also unduly discriminatory.

85. The North Dakota Commission disagrees with the Midwest ISO's distinction between the proposed treatment of GFAs and Integrated Transmission Agreements (ITAs). It asserts that non-Midwest ISO members providing service to their own non-Midwest ISO loads under ITAs with Midwest ISO members are neither participating in the Midwest ISO market nor receiving Midwest ISO transmission service and that abrogating such contracts would discourage efficient cooperation in the future.

(d) <u>Reply Comments</u>

86. On July 16, 2004, the Michigan/Kentucky Parties and the Rural Electric Cooperatives filed Reply Comments. The Michigan/Kentucky Parties argue that none of the parties who filed responses to the Commission's questions, nor any party to date, have provided any factual evidence sufficient to substantiate a claim that overrides the legal presumption in favor of honoring the terms and conditions of GFAs. Specifically, they argue that no party has: (1) presented evidence suggesting that keeping the GFAs

separate from the market would negatively impact reliability; (2) provided any quantification of the extent to which GFAs may shift costs to third parties; (3) or proffered any factual evidence to support an allegation that excluding GFAs will result in unduly discriminatory treatment. For example, the Michigan/Kentucky Parties point out that FirstEnergy admits that keeping GFAs separate from the market may not negatively affect reliability in the region. They also point out that Cinergy's comments state that GFAs must be integrated into the proposed structure to protect reliability and to capture market efficiencies, but that Cinergy mainly focuses on opposing Option B of the Midwest ISO's proposal which, the Michigan/Kentucky Parties state, is outside the scope of the Commission's narrow inquiry.

87. The Michigan/Kentucky Parties note that FirstEnergy admits that it made no effort to quantify the economic impact of carving out GFAs, and therefore, if there may be costs borne by non-GFA parties, the impact of any such alleged cost shifts is not known. Further, the Michigan/Kentucky Parties assert that, contrary to responding parties' claims, the different treatment GFAs may receive does not automatically equate to undue discrimination. Finally, they urge the Commission to engage in a forum to explore the issues involving the TEMT and to provide parties an opportunity to engage in discovery and cross-examination.

88. The Rural Electric Cooperatives also filed reply comments. They reemphasize that keeping the GFAs separate from the market would not shift costs to third parties since GFAs already exist, and are currently scheduled and operate reliably on the system, so there are no new incremental costs associated with supporting these GFA transactions. The Rural Electric Cooperatives argue that neither the Procedural Order, nor any of the other comments filed in this proceeding, explain how preserving GFAs would constitute undue discrimination under the proposed TEMT relative to non-GFA market participants.

3. Commission Discussion

89. We will not recite the analysis presented by Dr. McNamara and the IMM on how the Midwest ISO Energy Markets are managed. No party disputes these descriptions and they stand on their merits as summaries of the Midwest ISO energy market operations and they are sufficient for our purposes here. Thus, we find that, based on the evidence and analysis presented, the Midwest ISO can reliably operate the Day 2 Energy Markets with some GFAs that are carved out from TEMT scheduling, as discussed in the next section of this order. We acknowledge that a carve-out could result in inefficiencies that would result in additional costs for non-GFA transmission customers under the TEMT. However, even with a carve-out and the inefficiencies that could result, we believe that the Day 2 Energy Markets will be more reliable and efficient overall than the current Day 1 energy market.

90. We first address the reliability impacts of GFAs. The pertinent issue before the Commission is whether there are reliability impacts that result from how GFAs must be managed and scheduled by the Midwest ISO in the management and operation of its Energy Markets. "Carving out" GFAs in this context means that parties to GFAs are allowed to exercise the scheduling and energy management provisions of their GFAs in the same manner they did before the Energy Markets started.[49] We agree with Dr. McNamara that some interpretations of how to coordinate a physical carve-out with the scheduling and dispatching protocols under the TEMT might not be compatible with reliability, and hence should be excluded from consideration. As he states, parties with GFAs cannot operate "outside the market" in all senses, but must in certain respects follow the same scheduling practices as other users of the Midwest ISO system, such as specifying points of injection and withdrawal, to allow the Midwest ISO to perform its security-constrained economic dispatch (SCED) for the footprint.[50]

91. As characterized by the Midwest ISO, carved-out GFAs would not be required to schedule in the Day-Ahead Energy Market and would be allowed to submit their final physical schedules at some time just prior to real-time dispatch, and their imbalances need not be settled in the Real Time Energy Market.[51] As a consequence, the Midwest ISO would have to estimate GFA schedules in its Day-Ahead scheduling and Reliability Assessment Commitment (RAC) process that occur before the GFA schedule is submitted.[52] However, the estimation process may include some judgments on the appropriate level and spatial configuration for unit commitments, and the management of reserves. In the circumstance that the GFA carved-out schedules are incorrect, the Midwest ISO may have to obtain additional unit commitments or additional reserves in real-time, and possibly order TLRs and invoke emergency load shedding procedures. In

[49] We agree with Dr. McNamara that a physical carve out from actual dispatch is not possible. All GFA transactions must be dispatched by the Midwest ISO once they submit schedules. *See* McNamara testimony at 4.

[50] "Dispatch" refers here only to those generation units that are submitted into the Midwest ISO market and are hence dispatchable. Generation resources scheduled under GFAs will not be redispatchable, except in cases of emergency.

[51] We note that the Midwest ISO has identified that nearly 85 percent of the MW service entitlements associated with GFAs do not address scheduling or allow services without a scheduling obligation. *See* McNamara testimony at 62.

[52] *Id.* at 28.

short, accommodating GFAs into an energy market will increase the unpredictability and complexity of reliability planning for daily operations.

92. However, while we concur with the Midwest ISO that carving out GFAs presents reliability management challenges, we believe some GFAs could be accommodated with a carve out in the Energy Markets without threatening reliability for several reasons. In general, we believe that: (1) the increased scope of the Energy Market under the centralized dispatch will increase the availability of redispatch capability in the event of congestion; and (2) the measures taken to account for security constraints and other reliability requirements will enhance the ability of the system operator to anticipate and respond to reliability problems.

93. More specifically, this means that first, in the day-ahead and reliability unit commitment process, we expect that the Midwest ISO will take all steps necessary to ensure reliability of the dispatch by incorporating and evaluating GFA schedules and procuring sufficient generation capability in the reliability unit commitment and ancillary services to account for all likely circumstances.[53] Dr. McNamara confirms this conclusion when he states that the planning process for the Midwest ISO would still account for the impact of GFA schedules in its estimation process. We further note that the Midwest ISO TOs have offered to provide scheduling estimates for GFAs, as will also be discussed later in this order, thereby providing a better estimate of GFA schedules for the Midwest ISO Energy Markets.

94. Second, the real-time market, also accounting for security constraints, will provide more efficient and effective tools for managing congestion and reduce the need to resort to TLRs. The LMP-based real-time energy market will provide market participants, other than GFAs, with economic incentives to manage their energy sales, purchases and transmission use in a way that supports reliability and allocates grid use efficiently. For example, transmission usage will be priced to reflect the marginal cost of redispatching the grid to avoid security limits. Also, the SCED process, which allows the grid operator to continuously adjust generation dispatch every five minutes, ensures violations of security limits generally can be addressed before they occur.[54] Accordingly, we agree with the IMM that the SCED process will reduce TLRs.[55] Third, the small number of

[53] We recognize the negative consequence of this approach on costs, which we discuss in the economic efficiency discussion that follows.

[54] McNamara testimony at 9.

[55] *See* IMM Report at 9. We also note that Dr. Hogan draws the same conclusion. *See* Hogan testimony at 31.

GFAs that are being carved out of the Energy Markets, discussed more fully in the next section of this order, are not expected to pose a significant threat to reliability over the Midwest ISO grid.

95. Our general reliability concern is that NERC cites TLRs as a reliability threat; as we noted in our Procedural Order, when TLRs are invoked, the process by which dispatchers get back within the security limits is cumbersome and inefficient.[56] We agree with the Rural Electric Cooperatives that TLRs are a feature of other energy markets, and it is not realistic to expect they can be eliminated entirely.[57] Rather, the reliability imperative is to reduce TLRs to the extent possible, an objective we believe is achieved by centrally dispatched energy markets, including the Midwest ISO Energy Markets. We expect the Midwest ISO Energy Markets will be more reliable because of the incentives provided by the LMP market, the regional SCED process available to the Midwest ISO, and the reliability safeguards we instituted in the TEMT II Order.

96. At the same time, we recognize that there are some geographic areas that are more heavily influenced by transactions under GFAs (as well as self-scheduled transactions by non-GFA parties) than others, and therefore may require occasional resort to TLRs as a reliability management option. This circumstance would occur in the event that redispatch were required to relieve congestion and the Midwest ISO was unable to obtain sufficient redispatch capability from non-GFAs (*i.e.*, there were insufficient offers into the spot market), leaving TLRs as the only remaining option.

97. To ensure that we have addressed any potential reliability impacts of GFAs, we direct the Midwest ISO to report to us in 30 days if it identifies any reliability problems that would preclude successful operation of the Midwest ISO energy markets at start-up. This report must identify the problem, provide supporting schedules that document why the market can not operate reliably, identify specific contracts contributing to the problem and explain how it intends to resolve the problem.

98. We are not concerned that the Midwest ISO has not sufficiently quantified the reliability impact of GFAs. The description of the reliability management process

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[56] We note the analysis by the IMM that in 16 percent of the hours in which TLRs were called in 2003, under-curtailments occurred and that flows reached over 20 percent beyond the flowgate limit in a few instances. *See* IMM Report at 7.

[57] In this regard, we note Dr. McNamara's statement that the TEMT may not be able to eliminate TLRs due to the lack of a mechanism to hold external transmission customers responsible for redispatch costs. *See* McNamara testimony at 21.

provided by Dr. McNamara provides the factual description needed to assess how GFAs will be managed in the Midwest ISO Energy Markets, and therefore is sufficient for our purposes. Furthermore, other energy markets have successfully accommodated GFAs at the levels envisioned here without threatening system reliability.[58]

99. Turning next to the economic impact of a carve-out, as defined above, on non-GFA parties, we recognize that a carve-out of GFAs has the potential to result in additional costs for non-GFA transactions. However, we expect those impacts to be minor, in light of the small percentage of capacity to be carved-out. First, a carve-out will require that the full MW associated with such GFAs be withheld from the FTR allocation model, thus reducing the allocation of FTRs to non-GFA parties. This could increase exposure of some parties to net positive congestion charges (after FTR revenues are accounted for), and may require the Midwest ISO to seek new ways to provide additional congestion hedges for such parties. This could raise costs for non-GFA transmission users under the Midwest ISO TEMT. Second, while the Midwest ISO TOs' proposal to submit an indicative day-ahead schedule will assist the Midwest ISO in conducting a more efficient reliability unit commitment, the Midwest ISO will still have to use judgment in determining how to evaluate GFA schedules in that commitment. This will likely result in sub-optimal unit commitment, raising the costs of the reliability unit commitment, as noted by Cinergy and Dynegy. Third, the likelihood of inefficient scheduling by GFA holders will increase the costs of energy and congestion charges to non-GFA parties, thus potentially reducing the benefits of the Midwest ISO markets relative to what they might have been. For example, generation offered into the Energy Markets could be redispatched to accommodate inefficient GFA schedules, but only non-GFA market participants will be exposed to the resulting higher LMPs.

100. While carving out GFAs will clearly have negative consequences on efficiency in the Midwest ISO Energy Markets, we disagree with the contention of the Midwest ISO, in its August 17 informational filing, that a carve-out of GFAs will threaten the viability of centralized dispatch and Energy Markets. We note that the Midwest ISO position is predicated on a carve-out of approximately 15,000 MW,[59] whereas our analysis, discussed later in this order, identifies approximately 10,385 MW of carved-out GFAs

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[58] With respect to Cinergy's citation to PJM's comments (*See* Tabor testimony at 9) that express concern over potential difficulties with operating an LMP market with a very high proportion of loads under grandfathered contracts, we note that circumstance will not exist in the Midwest ISO Energy Markets where only a small percentage of loads will remain under carved-out GFAs.

[59] *See* Midwest ISO August 17, 2004 Informational Filing at 4.

which represents approximately 9.6 percent of the Midwest ISO's total peak load.[60] Given the scale and scope of the Midwest ISO Energy Markets, ample generation sources, scheduling estimation provided by the TOs, and a wide range of transmission options, we are not persuaded that a carve-out at this level would be notably detrimental to the efficient functioning of its Energy Markets during the GFA transition period.[61] Because implementing the TEMT even with a GFA carve-out will still expand the use of economic dispatch, aggregate costs under the new Day 2 markets should still be less than under the status quo Day 1 market and the overall efficiency of the market would improve.

101. Finally, we share the concerns expressed by parties that a carve-out could provide gaming incentives for GFA customers, especially those that also take service under the TEMT and therefore participate in the spot markets operated by the Midwest ISO. We agree with testimony submitted by Dr. Hogan that a GFA carve-out could create opportunities for market manipulation when GFA customers also participate in spot markets.[62] For example, day-ahead over-scheduling of GFAs to create "phantom" congestion may enhance the value of FTRs held under other network service contracts and therefore would also raise important concerns. Thus, we will require the IMM to monitor GFA customers for gaming behavior and provide an informational report to the Commission prior to the second FTR allocation. We further note that the TEMT II Order required the Midwest ISO to add Market Behavior Rule 2 to the TEMT.[63] This rule, which applies to transactions that manipulate market prices, would apply to scheduling behavior of GFAs.

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[60] Midwest ISO's peak load is 107,552 MW as reported on http://www.midwestiso.org/.

[61] As discussed earlier in the order, to the extent the Midwest ISO identifies problems that preclude successful start-up and operation of its energy market, those problems must be documented in a filing within 30 days.

[62] *See* Hogan testimony at 29.

[63] *See* TEMT II Order at P 356. In the TEMT II Order, we stated that, "[i]n exercising its discretion to determine the appropriate remedy for violations of Market Behavior Rule 2 … the Commission will apply the policies and principles set forth in Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC 61,218, *clarified*, 105 FERC ¶ 61,277 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004), and subsequent relevant precedent." *Id.* at P 356 n. 222.

102. We do not believe that any purpose would be served by the Midwest ISO submitting additional workpapers or holding further hearings, as some parties request. The analysis of the impacts of GFAs submitted by the Midwest ISO and its IMM and the accompanying explanations of their methods and assumptions are sufficient for our purposes here.

C. Analysis of the Midwest ISO Grandfathered Agreements

1. Background of Three-Step Fact-Finding Investigation

103. As stated above, in the Procedural Order, the Commission initiated a three-step investigation of the GFAs under section 206 of the FPA. The first step of the analysis required jurisdictional public utilities providing or taking service under GFAs (and invited any non-jurisdictional parties on a voluntary basis) to submit, on or before June 25, 2004, the following GFA information to the Commission: (1) the name of the GFA Responsible Entity, as defined in the proposed TEMT; (2) the name of the GFA Scheduling Entity, as defined in the proposed TEMT; (3) the source point(s) applicable to the GFA; (4) the sink point(s) applicable to the GFA; (5) the maximum number of megawatts transmitted pursuant to the GFA for each set of source and sink points; and (6) whether modification to the GFA is subject to a "just and reasonable" standard of review or a *Mobile-Sierra*[64] "public interest" standard of review.[65]

104. The Commission also stated that, if the parties to each GFA were able to agree on the GFA information, they should file the GFA information jointly and that the Commission would evaluate these joint filings as a group to help determine the effects of the GFAs on the proposed Energy Markets. If parties to a particular GFA or GFAs were not able to agree on the GFA information, then the Commission required each party to file its own interpretation of the GFA and proceed to Step 2 of the Commission's analysis.

105. Additionally, the Commission strongly encouraged GFA party settlements and stated that it would be receptive to GFA parties voluntarily agreeing, in settlement, to accept one of the Midwest ISO's proposed scheduling and settlement options, including

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[64] *See* United Gas Pipe Line Company v. Mobile Gas Service Corp., 350 U.S. 332 (1956); FPC v. Sierra Pacific Power Company (*Sierra*), 350 U.S. 348 (1956).

[65] By notice issued June 22, 2004, the Commission issued instructions to all parties for filing their GFA information and a template for filing summary GFA information.

Option B, for treatment of GFA transactions, or to convert their contracts to TEMT service.[66] The parties were directed to make a simple statement in their joint filings to indicate whether or not they were willing to voluntarily convert their contract to TEMT service or settle their GFA by accepting the Midwest ISO's proposed treatment of GFAs.[67] The Commission also stated that, if the Commission approved a settlement, it did not intend to later revisit its decision when it addressed the non-settling parties' GFAs.[68] Parties that did not settle their GFAs before July 27, 2004, would be subject to the Commission's analysis of how the GFAs should be treated in the Day 2 Energy Markets.[69]

106. In Step 2 of the analysis, the Commission considered all GFA information on which parties could not agree to be disputed issues of material fact and set such GFAs for hearing before two administrative law judges. The sole purpose of the hearing was to identify GFA information for every GFA on which the parties had not agreed by June 25, 2004.[70] The Commission required the presiding judges to issue written findings, and to present these written findings at the Commission meeting on July 28, 2004, on the same six informational GFA criteria required in Step 1 of our analysis.[71]

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[66] Procedural Order at P 80. The Commission stated that the GFA scheduling and settlement treatment options, including Option B, as drafted in the Midwest ISO proposal, would be available to GFA parties that jointly provided GFA information to the Commission in Step 1 (or prior to the conclusion of Step 2) of our three-step analysis, and that jointly indicated that they would accept this treatment. *Id.* at P 82.

[67] *Id.* at P 69

[68] *Id.* at P 80.

[69] *Id.* at P 78.

[70] The Commission held that hearing proceedings would begin on June 28, 2004, and terminate on July 23, 2004.

[71] Procedural Order at P 76. In the event that GFA parties reached an agreement on their GFA information prior to the conclusion of the Step 2 proceeding, they were directed to seek the presiding judges' permission to withdraw from the hearing. If the presiding judges granted permission, the parties were required to make a joint filing with the Commission as described in Step 1. Parties could voluntarily agree to convert or settle their GFAs in this filing no later than July 27, 2004, the day before the presiding judges' report issued. *Id.* at P 77.

107. In Step 3 of the analysis, following the presiding judges' oral presentation, the Commission stated that it would use the GFA information, and the other information and comments submitted in Step 1, to determine in a subsequent order (*i.e.*, the instant order): (1) whether the GFAs can function as written within the proposed Energy Markets; (2) whether the GFAs can function within the Energy Markets under the Midwest ISO's proposed treatment (which the Commission retains the right to amend); or (3) whether modifications to the GFAs should be required.[72]

108. On June 25, 2004, the Commission received numerous filings in Docket Nos. ER04-691-000 and EL04-104-000, including joint filings with templates and pre-filed testimony with exhibits.[73] At the June 28, 2004 hearing, the presiding judges informed the parties of the status of their filings under each contract, and noted that many joint filings contained insufficient responses under the six categories of GFA information.[74] On June 29, 2004, the presiding judges issued an order stating that those parties whose filings contained insufficient GFA information should contact the Secretary's Office to correct the deficiencies.[75] They also stated that those joint filings asserting that the contracts at issue did not belong in this proceeding should remain subject to Step 2 of the proceeding, pending issuance of a further order addressing those GFAs. On July 1, 2004, the presiding judges issued an order directing certain parties who had agreed with the Midwest ISO that their contracts should not be considered GFAs subject to the hearing to file a motion to withdraw on that basis.[76]

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[72] *Id.* at 78.

[73] Between June 23, 2004 – June 25, 2004, by the end of Step 1, 245 template filings and 255 other filings were submitted to the Commission, totaling 500 filings. Between June 25, 2004 – July 23, 2004, by the end of Step 2, there were 125 template filings and 242 other filings submitted to the Commission, totaling 367 filings.

[74] The hearing was conducted on June 28, 29, 30 and July 1, 8, 13, 16, and 20, 2004.

[75] Order Addressing Joint Filings in Docket Nos. ER04-691-000 and EL04-104-000, (June 29, 2004).

[76] Order Confirming Rulings in Docket Nos. ER04-691-000 and EL04-104-000 (July 1, 2004).

109. On July 2, 2004, the Commission issued an order directing certain incomplete joint filings involving GFAs to be included in the on-going Step 2 hearing.[77] Specifically, the Commission found that some parties failed to supply the requested data, failed to clearly specify the relationship between the services reported for each GFA so as to avoid double counting of services, or left undetermined whether modification to the GFA is subject to a "just and reasonable" standard of review or a *Mobile-Sierra* "public interest" standard of review. The Commission also directed that certain joint filings requesting that the associated GFAs be excluded from the proceeding remain in the hearing in order to: (1) establish the data required by the Procedural Order, to the extent that they are deficient; or (2) give the parties an opportunity to establish that the service provided under the GFA is such that it will not impact operation of Midwest ISO's Energy Markets.[78]

110. On July 6, 2004, the presiding judges ordered those parties whose joint filings were deemed deficient to file amended joint filings curing the deficiencies no later than July 9, 2004, or to appear on July 13, 2004 prepared to present their direct cases on those GFAs.[79] Those parties who jointly filed requests to be excluded from the proceedings were ordered to file motions to withdraw by July 9, 2004. The parties were directed to provide in their motions reasons for the request and establish that the service provided under the GFAs will not impact the operation of the Midwest ISO Energy Markets.

111. During the course of the Step 2 proceedings, the presiding judges continued to evaluate joint filings to ascertain whether the GFAs should be withdrawn or included in the Step 2 proceedings, or whether further information was required to make such a preliminary determination.[80] The presiding judges also issued orders granting motions to withdraw certain GFAs, and various other GFAs were added to the proceeding during the

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[77] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,006 at P 10 (2004) (July 2 Order). Attachment A to the order contained a list of GFAs for which joint filings had been found to contain one or more deficiencies.

[78] *Id.* at P 16.

[79] Order Establishing Further Procedures and Ruling on Joint Stipulation Regarding GFA No. 111 in Docket Nos. ER04-691-000 and EL01-104-000 (July 6, 2004).

[80] At the hearing on July 8, 2004 and in a subsequent electronic communication, the parties were given contact information for non-decisional Commission staff members who provided individual counseling to the parties.

process. In addition, in conformance with the guidelines listed in the Commission's July 2 Order, the presiding judges and non-decisional staff[81] continued to work with the parties that filed joint templates in Step 1 (*i.e.*, parties that were not explicitly directed to participate in the Step 2 hearing) to further improve their jointly-filed information.[82]

112. On July 21, 2004, the presiding judges issued an order terminating Step 2 proceedings with respect to certain GFAs with cured template deficiencies.[83] Orders terminating Step 2 proceedings were also issued on July 22, 2004[84] and July 23, 2004,[85] regarding other GFAs.

2. Presiding Judges' Findings of Fact

113. On July 28, 2004, the presiding judges presented their Findings of Fact in this proceeding to the Commission at its open meeting and issued written Findings of Fact.[86] The presiding judges found that a total of 450 GFAs were identified in Steps 1 and 2, and that 235 of those should be excluded from this proceeding, as they did not provide transmission service or were otherwise outside the scope of the Commission's inquiry. Of the 215 contracts that remained, the presiding judges found that the parties to 152, or 71 percent, filed joint answers to all six of the Commission's questions, indicating that they agreed on the GFA information the Commission had sought in the Procedural Order.

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[81] By notices issued May 6, 2004 and June 8, 2004, the Commission designated a total of six members of its decisional staff as non-decisional employees and non-decisional authorities for purposes of these dockets.

[82] Findings of Fact at P 32.

[83] Order Requiring Further Submission of Evidence, Docket Nos. ER04-691-000 and EL04-104-000 (July 21, 2004).

[84] Order Terminating Step 2 Proceedings With Respect to Certain GFAs with Cured Template Deficiencies, Docket Nos. ER04-691-000 and EL04-04-000 (July 22, 2004).

[85] Order Terminating Step 2 Proceedings With Respect to Certain GFAs with Cured Template Deficiencies, Docket Nos. ER04-691-000 and EL04-104-000 (July 23, 2004).

[86] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 63,013 (2004) (Findings of Fact).

The parties to 91 of these 152 contracts reached agreement on the GFA information in Step 1 of the proceeding; the parties to 61 of these contracts reached agreement in Step 2 of the proceeding. The presiding judges determined the GFA information of 52 more contracts (24 percent of the total included in the investigation).[87] They also found that the Commission received no filings for 11 contracts (5 percent of the total), as the parties are not public utilities under section 201 of the FPA[88] and chose not to voluntarily submit information. During Steps 1 and 2, a total of 52 parties settled their contracts by mutually agreeing to accept one of the TEMT options for GFA treatment. Those parties chose Option A, Option B, a combination of Options A and B for their initial treatment upon the commencement of Midwest ISO's Energy Markets or chose to convert the transmission service under their contract to service under the transmission and energy markets provisions of the TEMT.

114. In their Findings of Fact, the presiding judges stated that, in accordance with the July 2 Order, they had evaluated for sufficiency: (1) the numerous revised joint filings that parties made to cure deficiencies in their initial filings; and (2) the joint templates of parties who came to agreement during the hearing on all GFA information.[89] The presiding judges also stated that they had evaluated for sufficiency the data in filings associated with contracts that were added during the proceeding.[90] In addition, the judges stated that they had interpreted the July 2 Order expansively in order to provide the best record possible to the Commission.[91]

115. As discussed more fully below, the presiding judges made determinations with respect to the Step 2 GFAs, including findings regarding the appropriate GFA

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[87] The 52 disputed contracts that proceeded to Step 2 for hearing included: GFA Nos. 205, 206, 207, 215, 220, 221, 267, 268, 269, 273/311, 274/320, 284, 293, 297, 300, 302, 304, 306, 308, 309, 313, 314, 316, 317, 321, 352, 354, 360, 361,364, 365, 374, 377, 389, 391, 409, 410, 411, 415, 431, 432, 433, 434, 435, 436, 437, 438, 439, 440, and 450.

[88] 16 U.S.C. § 824 (2000).

[89] *See* Findings of Fact at P 30.

[90] The judges explained that this information is in a database that was created for this proceeding and is available for the Commission's use in the Office of Markets, Tariffs and Rates. Public versions of these records were appended to the Findings of Fact as Attachment A. *See id.*

[91] *Id.* at P 32.

Responsible Entity, GFA Scheduling Entity, and the appropriate standard of review for modifications to the GFAs.

116. As pertinent here, regarding the presiding judges' determination of the appropriate standard of review for contract modification, *i.e.*, whether modification to a GFA is subject to the "just and reasonable" standard of review or the *Mobile-Sierra* public interest standard of review, the presiding judges permitted parties that could not agree on the applicable standard of review to supplement the record by filing legal memoranda in support of the appropriate standard of review.[92]

117. The presiding judges explained that, under the *Mobile-Sierra* doctrine, "the Commission is permitted to exercise its rate-making authority to abrogate private contracts that are subject to a 'public interest' standard where the public interest 'imperatively demands' such action."[93] Correspondingly, they further explained that, under the public interest standard, the Commission may enforce the terms and conditions of a contract even if they are unjust and unreasonable. The presiding judges asserted that this standard differs from the just and reasonable standard, which simply reflects that all rates, terms and conditions be just and reasonable. As a result, the public interest standard is more difficult to meet than the just and reasonable standard.[94]

118. The presiding judges ultimately held that in cases where the GFA does not contain any explicit language providing the parties with unilateral filing rights, the applicable standard of review for modifications initiated by the parties would be the *Mobile-Sierra* public interest standard of review. However, if that contract also did not contain language that limited the Commission's ability to modify the contract, the presiding judges found that any changes initiated by the Commission would be subject to the just and reasonable standard of review.[95]

119. On August 17, 2004 the parties listed in Appendix A to this order filed briefs on exceptions to the presiding judge's July 28, 2004 Findings of Fact. The parties raised numerous issues, including, among other things, exceptions with respect to the presiding

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[92] *Id.* at P 41.

[93] *Id.* at P 43 (*citing* Metropolitan Edison Co. v. FERC, 595 F.2d 851, 856 n.29 (D.C. Cir. 1979)).

[94] Findings of Fact at P 44.

[95] *Id.* at P 47.

judges' findings on the GFA Responsible Entity, GFA Scheduling Entity and appropriate legal standard, as discussed more fully below.

3. Parties' Comments on GFA Modification

(a) May Comments Regarding GFA Modification

120. In their May Comments on the Midwest ISO's proposed TEMT, the Midwest ISO TOs state that the Midwest ISO effectively seeks to revise existing contracts without the appropriate legal requirements being satisfied, or it is seeking to impose charges on public utilities to those GFAs without those utilities having a reasonable opportunity to recover the costs. They believe that the Midwest ISO has failed to make the necessary showing under the *Mobile-Sierra* doctrine that revision of the existing contracts meets the public interest standard. Further, the Midwest ISO TOs state that there is no operational reason that the Midwest ISO cannot operate by excluding the GFAs, much as PJM operates its market. The Midwest ISO TOs state that they are willing to provide the Midwest ISO with the operational information that it needs in order to implement the market with a carve-out for the GFAs that would hold the GFAs harmless from any market-related costs and charges.

121. The Midwest ISO TOs are primarily concerned that the Midwest ISO's proposed options for treatment of GFAs under the TEMT will lead to trapped costs and unlawful modification of contracts. Under the Midwest ISO's proposed options, GFAs may be exposed to congestion and marginal loss costs associated with schedule changes, uplift to cover congestion and losses revenue shortfalls, and Schedule 16 and 17 costs. The Midwest ISO TOs state that there is currently no method for recovery of such costs in the GFAs, so the costs will become trapped. Therefore, they recommend that the Commission reject the Midwest ISO's proposal for treatment of GFAs.

122. Montana-Dakota argues that the Midwest ISO's GFA proposal will impose additional costs without yielding additional benefits. Montana-Dakota asserts that it is unjust to permit the imposition of additional costs that cannot be passed through to the customers that cause the costs to be incurred. Therefore, it urges the Commission to require the Midwest ISO to leave all GFAs in their original state by treating them like non-Midwest ISO load. Accordingly, Montana-Dakota argues that section 38.8 of the TEMT should be removed from the tariff, leaving GFAs intact.

123. In its May Comments, Dairyland argues against Commission acceptance of the three options for GFA treatment proposed in the TEMT. It argues that the options abrogate existing contracts by not preserving their original terms in regards to congestion and losses. Crescent Moon Utilities argue that the Midwest ISO's proposal is

unacceptable because it represents an unlawful attempt to extend the TEMT's jurisdiction to Crescent Moon's non-jurisdictional contracts.

124. WPS Resources argues that the Midwest ISO's proposal to allow GFA parties to identify the quantity and quality of grandfathered transmission services, that are not obvious in the contract, will allow GFA parties to capture more valuable FTRs or recover more congestion revenues than are appropriate. As a result, WPS Resources asks that contracts with ambiguous critical terms not be granted GFA status.

(b) June and Reply Comments Regarding GFA Modification

125. In their June Comments, the Midwest ISO TOs also reiterate their concern that the Midwest ISO is seeking to take actions contrary to the Midwest ISO Agreement. These actions include seeking to impose additional costs associated with GFAs through their options proposal and not preserving the GFAs for at least the transition period ending in 2008. They state that by accepting changes to the GFAs, in particular assigning them additional costs associated with congestion and losses, the Commission is sending a signal to the industry that it cannot rely on the initial orders in RTO/ISO formation. They extrapolate that transmission owners that are reluctant to join an RTO will become more so if the Commission changes the provisions in the Midwest ISO Agreement on which the Midwest ISO TOs based earlier decisions.

126. The Midwest ISO TOs dispute Dr. Hogan's testimony at 14, describing his "next best" solution to full conversion to TEMT service. They reiterate that if the Transmission Owner is obligated to pay the costs of the TEMT, but the GFA does not provide for a pass-through of those costs, the Transmission Owner cannot recover its costs and those costs will become essentially "trapped." The Midwest ISO TOs assert that this violates longstanding precedent to afford utilities the opportunity to recover prudently incurred costs.[96] Instead, they request that the Commission adopt their proposal to provide day-ahead scheduling information for energy flows pursuant to GFAs in exchange for carving GFA transactions out of the market, including exempting GFA transactions from Schedule 16 and 17 charges.

127. According to OMS, it is possible to carve-out GFA transactions by allowing settlements of energy to include both the real-time load and real-time generation used to serve that load via GFAs. The party responsible for scheduling energy under the GFA would need to indicate anticipated GFA use in the day-ahead schedule, but would be

[96] Midwest ISO TOs' June Comments at 13 (*citing* FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)).

allowed to make adjustments to the schedule prior to the real-time market. OMS warns, however, that limitations to the amount of adjustments allowed must be made to preserve system reliability.

128. OMS contends that exempting GFAs from the scheduling requirements of the TEMT would be discriminatory because it would allow some participants to adjust their schedules between the day-ahead and real-time markets while others could not. However, OMS asserts that whether the discrimination is undue depends on the impact such a carve-out will have. Moreover, OMS argues that the energy imbalance market is not a major issue when dealing with GFAs as long as buyers are not forced to schedule their loads and pay imbalance charges. OMS believes that allowing substitute loss calculations for each GFA contract will have an economic impact on the pool of dollars available to refund to third-party market participants. OMS argues that it would be unduly discriminatory to allow the loss provisions of the GFA contracts to substitute for the Midwest ISO calculations.

4. Discussion Regarding GFAs That Did Not Settle

129. The Commission's three-step analysis of the GFAs was intended, among other things, to ascertain the effects of the Energy Markets on the GFAs, and the effect of the GFAs on the Energy Markets. As part of the investigation, the Commission offered the parties to the GFAs an opportunity to settle on the GFA treatment that the Midwest ISO proposed in the TEMT. A major benefit of the settlement option was to make the mutual impacts of the GFAs and the Energy Markets immediately apparent to the Commission and the parties. A total of 52 parties settled GFAs representing 9,728.5 MW by either electing one of the proposed treatment options or by agreeing to convert their contracts to TEMT service.

130. Our analysis of the information submitted by the parties to the remaining GFAs indicates, in sum, that: (a) 50 GFAs, representing 4,992.7 MW, have not settled and are subject to a just and reasonable standard of review; (b) 77 GFAs, representing 6,914.4 MW, have not settled and the parties have explicitly provided that the *Mobile-Sierra* public interest standard of review applies; (c) 20 GFAs, representing 1,272.9 MW have not settled, are disputed as to the standard of review, and the GFA is silent as to the standard of review; and (d) the entity providing transmission service under 30 GFAs, representing 2,198 MW, is not a public utility under the FPA. Consequently, the proper treatment of GFAs representing only 15,378 MW, or only 14.3 percent of the Midwest ISO's peak capacity, remains in dispute. The Midwest ISO's March 31 Filing, in contrast, originally sought modification of contracts representing more than 2½ times that much capacity. We are pleased that the parties and the presiding judges were able to resolve such a significant amount of the contracts. Reducing the magnitude of what is carved-out will minimize the operational problems such contracts create.

131. In accordance with Opinion Nos. 453 and 453-A, the Midwest ISO Tariff requires Transmission Owners and ITC Participants to take network or point-to-point service pursuant to a service agreement under the Midwest ISO Tariff in order to meet their transmission service obligations under the GFAs.[97] This is consistent with the Commission's requirement that an RTO have operational authority for all transmission facilities under its control.[98] Transmission Owners and ITC Participants that take service under the Midwest ISO Tariff for GFA transactions are not required to pay charges under Schedules 1 through 9 to the Midwest ISO Tariff, and they are not responsible for losses under Attachment M of the Midwest ISO Tariff, but they must pay Schedule 10 charges for service they take for delivery to load located within the Midwest ISO footprint.[99] When it required the Midwest ISO to assess Schedule 10 charges for all GFA load located inside the Midwest ISO, the Commission reasoned that all users of the grid operated by the Midwest ISO "benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability . . . ."[100] The court upheld the application of Schedule 10 charges for load served under GFAs,[101] although the rates, terms and conditions of GFAs themselves are honored throughout the six-year transition period.

132. As discussed above, there are many benefits associated with the Day 2 markets that the Midwest ISO has proposed. The Midwest ISO asserted, and the Commission concurs, that bulk power markets with centralized dispatch facilitate more efficient operation of the transmission system and increase transmission system reliability.[102] All users of the transmission system, including parties to GFAs, will share in these benefits.

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[97] Midwest Independent Transmission System Operator, Inc., *et al.*, Opinion No. 453, 97 FERC ¶ 61,033 at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand*, 102 FERC ¶ 61,192 (2003), *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom.* Midwest ISO Transmission Owners, *et al.* v. FERC, No. 02-1121, *et al.* (D.C. Cir. July 16, 2004). *See also* Midwest ISO Tariff at section 37.1.

[98] *See* 18 C.F.R. § 35.34(j)(3) (2004); Opinion No. 453 at 61,169-70; Opinion No. 453-A at 61,411; Order No. 2000 at 31,086-107.

[99] *See* Midwest ISO Tariff at section 37.3.

[100] *See* Opinion No. 453 at 61,169.

[101] *See* Midwest ISO Transmission Owners, *et al.* v. FERC, 373 F.3d 1361, 1367-69 (D.C. Cir. 2004).

[102] *See* TEMT II Order at P 62.

133. There are new rules for operation and settlement of the Midwest ISO's new Energy Markets, and the new rules differ significantly from the service currently provided under the GFAs and the Midwest ISO Tariff. Non-grandfathered transactions, as discussed in the TEMT II Order, will be placed under the TEMT and will become subject to the new scheduling and settlement procedures. As discussed above, if all of the GFAs remain in effect without modification or accommodation, the Midwest ISO will be required to operate with multiple scheduling procedures and added complexity in its settlement procedures. This could lessen the gain in both efficiency and reliability expected to result from the Day 2 markets. The Midwest ISO therefore proposes to change its relationship to the GFA parties when the Day 2 markets are implemented.

134. Specifically, the Midwest ISO proposes to account for the operational differences between the TEMT and the GFAs by requiring parties to GFAs to select one of three options for how their GFA should be treated in the Day 2 markets. The three options, which the Midwest ISO calls Option A, Option B and Option C, essentially modify the rates, terms, and conditions of service that Transmission Owners and ITC Participants take under the Midwest ISO Tariff to meet their GFA obligations.[103] Other parties have proposed carving the GFAs out of the Energy Markets and letting the contracts continue without requiring the Transmission Owners and ITC Participants, or their counterparties under the GFAs, to accept the responsibilities associated with the TEMT, for the interim period until 2008.

135. As described in the Procedural Order, we have used the results of Steps 1 and 2 of the investigation in this docket to determine the proper treatment of the GFAs during the transition period. We have examined: (1) the information that GFA parties submitted for each contract; (2) the analysis and written comments submitted regarding the impact of GFAs on the Energy Markets, and the Energy Markets on the GFAs; (3) the presiding judges' conclusions as reported in their Findings of Fact; and (4) the Briefs on Exceptions thereto. As explained further below, we distinguish four categories of GFAs that did not agree to settle on the treatment proposed by the Midwest ISO. These categories are: (1) GFAs subject to the just and reasonable standard of review; (2) GFAs where the parties have explicitly provided that the *Mobile-Sierra* public interest standard of review applies; (3) GFAs that are silent on the standard of review; and (4) GFAs under which the entity

[103] For example, the Midwest ISO's proposed Option B, which it expected the majority of GFA parties to elect, would require the Scheduling Entity for a GFA to submit a day-ahead schedule or incur charges for congestion and losses. This is not currently required under the OATT. *See infra* Section D of this order (describing Options A, B and C).

providing service is not a public utility. We will require the Midwest ISO to integrate the first group of GFAs into the Energy Markets and to carve out the latter three groups, *i.e.*, not require that the terms and conditions of the TEMT apply to transactions under this latter group of GFAs.

(a) GFAs Subject to the Just and Reasonable Standard of Review

136. The Midwest ISO TOs and other commenters are concerned that accepting the Midwest ISO's proposed treatment of GFAs in the Energy Markets is tantamount to revising the GFAs and will lead to trapped costs. The Midwest ISO, as described above, argues that, with an estimated 40,000 MW of capacity covered by GFAs, it will be unable to reliably operate the Energy Markets if the GFAs do not participate.

137. In order to balance the Midwest ISO TOs' concerns that the Midwest ISO's proposed treatment of GFAs will lead to trapped costs with the Midwest ISO's concern that leaving GFAs intact will negatively impact reliability, the Commission finds that it is unjust and unreasonable to allow GFAs that are subject to a just and reasonable standard of review to remain outside the Midwest ISO Energy Markets. It is just and reasonable to accept the Midwest ISO's proposed treatment of GFAs for those GFAs that did not settle and that are subject to a just and reasonable standard of review.[104] Including transactions under these contracts (50 GFAs, representing 4,992.7 MW) in the Energy Markets will better enable the Midwest ISO to operate those markets reliably and will not contravene the contractual rights of the parties to the GFAs.

138. The proposed TEMT does not rewrite the GFAs, although it does impose changes to the manner in which transmission service is provided for transactions under the GFAs. Thus, for example, Option A requires the GFA Responsible Entity to nominate and hold FTRs in order to transact under GFAs, and Option C requires the GFA Responsible Entity to pay the costs of congestion for all GFA transactions. As such, it is possible that replacing the current OATT with the TEMT, including its proposed treatment of GFAs, may affect the bargain between parties to individual GFAs. To the extent that costs are shifted between parties to GFAs in this category, the terms and conditions of GFAs subject to a just and reasonable standard of review allow the parties to propose

[104] We determined that 50 of the non-settling GFAs are subject to a just and reasonable standard of review. Of those, parties to 31 of these GFAs explicitly agreed that their contracts are subject to a just and reasonable standard of review. For the remaining 19 GFAs, the presiding judges made a finding that the contracts are subject to a just and reasonable standard of review, and we affirm those findings.

appropriate modifications to reflect such new costs.[105] We find that this flexibility will adequately protect the parties to this category of GFAs from trapped costs.

139. Accordingly, we will require the Transmission Owners and ITC Participants providing service under these GFAs, either unilaterally or through agreement with their counterparties, to choose between the scheduling and settlement provisions of Option A or Option C (which we find are just and reasonable, as described below), and to notify the Midwest ISO of their selection, in accordance with the TEMT, before the commencement of FTR nominations.[106]

140. We disagree with the Midwest ISO TOs that our action here is precluded by the Midwest ISO Agreement. The Midwest ISO Agreement, by its express terms, does not abrogate GFAs or allow the Midwest ISO to modify the terms. However, it does not prevent the Commission or GFA parties from seeking modification to the GFAs pursuant to the GFAs' own terms. Our action in this docket makes the latter type of modification, and therefore is not barred by the Midwest ISO Agreement.[107]

(b) GFAs Where the Parties Have Explicitly Provided that the *Mobile-Sierra* Public Interest Standard of Review Applies

141. After the settled GFAs, plus the non-settled GFAs where the parties have explicitly provided that the just and reasonable standard of review applies, have been integrated into the markets, relatively few GFAs remain: 127 GFAs, representing 10,385.2 MW. Of these, 77 GFAs, comprising 6.914.4 MW, the parties have explicitly

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[105] As described above, the Commission expects that the increases in efficiency and competitiveness that accompany the implementation of the Energy Markets will offset these increased costs.

[106] *See* Module C, Section 38.8.3, Original Sheet No. 445.

[107] *See* Louisville Gas & Electric Company and Kentucky Utilities Company, 101 FERC ¶ 61,182 (2002), *reh'g denied* 103 FERC ¶ 61,104 (2003) (finding that Opinion 453-A was not intended to deny transmission owners the opportunity to recover from GFA customers the charges that Midwest ISO levies on transmission owners for service provided under GFAs, or require negotiation prior to the transmission owners' petitioning the Commission for change to the rates, terms or conditions of GFAs, where the GFAs themselves do not require such negotiation).

provided that they are subject to a *Mobile-Sierra* public interest standard of review.[108]

142. The Midwest ISO has requested that we modify all GFAs, including those subject to review under the *Mobile-Sierra* public interest standard, to ensure that it can reliably operate its Energy Markets. However, as described in the previous section, the record before us suggests that the Energy Markets, which are scheduled to start up on March 1, 2005, can be operated reliably, with net benefits to the public, notwithstanding a carve-out of these 77 GFAs until the transition period ends in 2008. We therefore cannot find today that the public interest requires that these GFAs be modified in order for the Energy Markets to operate reliably.

143. Thus, we will direct the Midwest ISO to carve these GFAs out of the Energy Markets for the remainder of the six-year transition period. A carve-out for this category of contracts, we reiterate, is possible only because of the small number of megawatts involved; larger carve-outs, in contrast, would require us to reevaluate this treatment (which, in any event, will terminate in 2008).[109]

144. Although these GFAs will not be subject to the TEMT's scheduling requirements, the Midwest ISO TOs stated in their comments that they are willing to provide non-binding day-ahead schedule information for GFAs to the Midwest ISO.[110] We accept the Midwest ISO TOs' offer. We direct them, to the extent that they take service under the Midwest ISO Tariff to meet their obligations under the GFAs in this category, to submit day-ahead and modified real-time schedules to the Midwest ISO in accordance with the timelines set forth in the TEMT.[111] This additional information will allow the Midwest ISO to better accommodate the GFAs that we are temporarily exempting from the responsibilities of the TEMT through the end of the transition period, and further minimize the impact of the carve-out on the Day 2 markets. We expect these schedules

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[108] Twenty additional GFAs are silent as to the standard of review, and remain disputed; the transmission providers for 30 remaining GFAs are not jurisdictional public utilities.

[109] Formation Order at 62,167-70; Ameren Services Co., *et al.*, 103 FERC ¶ 61,178 at P 72 (2003).

[110] *See* Midwest ISO TOs' June Comments at 16, 20 and Attachment A at 4. Hoosier and Southern Illinois, which are not public utilities under section 201 of the FPA, have joined the Midwest ISO TOs' comments.

[111] *See* Midwest ISO TEMT §§39.1.1 and 40.1.1.

to be as accurate as possible and will direct the Midwest ISO to file, on an informational basis, quarterly reports on the accuracy of the day-ahead schedules submitted for these GFAs within 30 days after the end of each calendar quarter.

145. We direct the Midwest ISO to file, within 60 days of the date of this order, a detailed explanation of how it will administer the carve-out. The Midwest ISO should include the following parameters in designing the carve-out: (1) the maximum MW capacity designated in this proceeding for each carved-out GFA should be removed from the model used for FTR allocation; (2) schedules submitted by the GFA parties in accordance with the TEMT day-ahead timelines should not be subject to congestion charges; (3) the Midwest ISO should incorporate the GFA parties' schedules into the Reliability Assessment Commitment procedures; and (4) the Midwest ISO should allow parties to carved-out GFAs to settle real-time imbalances through the provisions of their GFAs instead of requiring that such imbalances be procured through the Midwest ISO Real-Time Energy Market during the transition period.

146. OMS raises concerns about the unequal treatment of GFA transactions and non-GFA transactions in the new Energy Markets. It concedes that whether the discrimination is undue depends upon the impact that the carve-out will have, but highlights as unduly discriminatory the substitution of loss provisions in GFA contracts for those in the TEMT. Requiring parties to GFAs that are subject to a just and reasonable standard of review to abide by the scheduling and settlement rules that the Midwest ISO proposed for GFAs will help level the playing field and more appropriately distribute the costs of the Day 2 markets. The capacity under remaining GFAs – 10,385.2 MW, or 9.6 percent of the Midwest ISO's peak capacity – is sufficiently small that it will not harm the Midwest ISO's ability to provide service reliably. With respect to losses, OMS's concerns are premature. The TEMT II Order required the Midwest ISO to credit marginal losses back to a historical loss charge or average losses for all existing transmission customers for a five-year transition period and for all new transmission customers for a one-year transmission period.[112] In addition, the Commission required the Midwest ISO to pursue with stakeholders methods for ensuring that they are not significantly exposed to marginal loss charges without an opportunity to hedge against such charges; one such method may be to modify the loss pool mechanism.[113] The Commission directed the Midwest ISO to file revised proposals with the Commission to implement this transitional loss calculation measure and propose a long-term solution to address concerns about the lack of hedging mechanisms for marginal losses. If OMS's

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[112] *See* TEMT II Order at P 73-78.

[113] *See id.* at P 239.

concerns about undue discrimination persist, it may raise those at the time those proposals are filed.

(c) GFAs With No Specified Standard of Review

147. Our review of the presiding judges Findings of Fact indicate that there are 16 additional GFAs, representing approximately 1,240 MW, for which the parties did not agree on what standard of review applies and that the presiding judges' found are silent on the standard of review. The presiding judges determined that the public interest standard applies to these GFAs.

148. Xcel argues on exceptions that the presiding judges erred in finding that four of its disputed GFAs do not permit unilateral rate modifications and are subject to the *Mobile-Sierra* public interest standard of review.[114] It alleges that those contracts are in fact silent as to the applicable standard of review. [115]

149. We will require the Midwest ISO to carve out these 20 "silent" contracts until the transition period ends in 2008[116] because the record before us suggests that the Energy Markets, which are scheduled to start up on March 1, 2005, can be operated reliably, with net benefits to the public, notwithstanding the carve-out of these 20 GFAs. We also require that the Transmission Owners and ITC Participants taking transmission service under the Midwest ISO Tariff to meet their obligations under these contracts submit day-ahead and modified real-time schedules to the Midwest ISO so that the Midwest ISO can handle transactions under these GFAs in the most efficient way possible. The Midwest ISO is directed to include day-ahead schedules for these contracts in its quarterly reports on schedules for carved-out GFAs.

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[114] *See* Findings of Fact at P 119.

[115] Xcel Brief on Exceptions at 17-18.

[116] The four contracts (totaling 32.4 MW) Xcel disputes will be included in the carve-out whether they are silent as to standard of review, as Xcel alleges, or whether they are subject to the *Mobile-Sierra* public interest standard, as the presiding judges found. Therefore, as further described *infra* in Section II (C)(5)(c), we do not need to make a finding as to the standard of review for these contracts.

(d) Non-Jurisdictional GFAs

150. Finally, we will require the Midwest ISO to carve out of the Energy Markets the 30 GFAs, representing 2,198 MW, for which the transmission provider is not a public utility as defined in section 201 of the FPA. The Commission has no authority to make any modifications to these contracts. However, the Commission does have jurisdiction over the service that the Transmission Owners must take under the Midwest ISO Tariff to meet their obligations under their GFAs. In addition, we note that Hoosier and Southern Illinois have joined the Midwest ISO TOs' comments, which state that the Midwest ISO TOs can submit correct, day-ahead schedules to the Midwest ISO. We accept this offer, and will require that Transmission Owners taking transmission service under the Midwest ISO Tariff to meet their obligations under GFAs in this category submit day-ahead and modified real-time schedules to the Midwest ISO so that the Midwest ISO can handle transactions under these GFAs in the most efficient way possible.[117] To the extent that the Midwest ISO receives (or does not receive) day-ahead schedules for these contracts, it is directed to include them in its quarterly reports on schedules for carved-out GFAs or to specify that it did not receive them.

5. Discussion Regarding the Briefs on Exceptions to the Presiding Judges' Findings of Fact

(a) GFA Responsible Entity

151. The presiding judges' in their Findings of Fact stated that, for nearly all of the GFAs set for hearing, the designation of the GFA Responsible Entity was disputed.[118] They asserted that finding the GFA Responsible Entity for each of the contracts, as defined in the TEMT,[119] required them to consider the Commission's prior precedent

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[117] We note that Southern Illinois and Hoosier are the only two non-jurisdictional Transmission Owners subject to the carve out, since other non-jurisdictional Transmission Owners (e.g., City of Columbia, Springfield City Water and Light) either do not have GFAs or have settled on one of the options proposed in the Midwest ISO TEMT.

[118] Findings of Fact at P 34.

[119] The TEMT describes the GFA Responsible Entity, Module C, § 38.8.1, Original Sheet No. 443, as follows:

a). The GFA Responsible Entity must be a fully qualified Market

(continued)

regarding RTOs and ISOs and that these principles were applicable to the issues set for hearing.[120] They explained that, in recent cases involving assignment or "pass-through" of RTO and ISO costs and charges, the Commission's policy has consistently been that it is appropriate to assign RTO and ISO costs to all customers using the grid, because all customers benefit from independent operation of the grid.

152. Under these precedents, the presiding judges stated that the transmission customer or the load-serving entity would be responsible for the charges that the GFA Responsible Entity would be obligated to pay under the TEMT. For the GFAs at issue in this proceeding, they found that these principles, standing alone, would require that the GFA Responsible Entity be the customer taking service over Midwest ISO facilities, because that customer is utilizing the grid and benefiting from its operation.[121] However, the presiding judges stated that the TEMT definition of GFA Responsible Entity in many cases prevents this finding, because it requires that the GFA Responsible Entity be a fully qualified Market Participant.[122] Accordingly, where the customer taking service under

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Participant under this Tariff.

b). The GFA Responsible Entity shall be financially responsible pursuant to the applicable GFA for:

(1) All Market Activities charges, as well as all charges under Schedules 16 and 17;

(2) All Transmission Usage Charges caused by the applicable Bilateral Transaction Schedules; and

(3) Any debits or credits associated with FTRs held by the GFA Responsible Entity.

[120] Findings of Fact at P 36 (*citing, inter alia,* Midwest Independent Transmission System Operator, Inc., 98 FERC ¶ 61,141 (2002); Pacific Gas & Electric Company, *et al.*, 101 FERC ¶ 61,151 (2002); California Independent Transmission System Operator, 103 FERC ¶ 61,114 (2003) (Opinion No. 463), *order on reh'g*, 106 FERC ¶ 61,032 (2004) (Opinion No. 463-A)).

[121] Findings of Fact at P 38.

[122] Under § 1.184 of the TEMT, Market Participant is defined as:

(continued)

the GFA was not a fully qualified Market Participant under the TEMT, the presiding judges found that the counter-party was the GFA Responsible Entity by default.

(1) <u>Parties' Exceptions</u>

153. A number of parties filed exceptions to the presiding judges' determination as to which party to the GFA should be the GFA Responsible Entity. GFA customers under the GFAs generally argue that the presiding judges misapplied Commission precedent. They argue that the precedent relied upon involves the pass-through to GFA customers of costs incurred by transmission owners taking service from an RTO to serve their GFA obligations. In fact, they state, Opinion Nos. 453 and 453-A actually stand for the opposite proposition because, in that proceeding, the Commission specifically rejected requests to allow the Midwest ISO to charge its Schedule 10 adder directly to GFA customers.[123]

154. With regard to the presiding judges' reliance on Opinion Nos. 463 and 463-A, in which the Commission approved Pacific Gas and Electric Company's (PG&E) proposal to pass through to GFA customers the costs that PG&E incurs with respect to the CAISO grid management services, commenters note that the Commission did not address in those orders whether the CAISO could charge GFA customers directly for those costs, as it had already been resolved that the transmission owners, and not the customers, would be assessed the costs in the first instance. They note that the Commission based its approval of PG&E's proposal on the finding that CAISO's grid management services, which include performing operation studies, system security analysis, emergency management, outage coordination, and transmission planning, were new services not provided for in existing contracts, that benefit GFA customers. In doing so, the Commission distinguished CAISO's grid management services from the reliability service (*i.e.*, redispatch) costs that the Commission previously had not allowed to be

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> An entity that (i) has successfully completed the registration process with the Transmission Provider and is qualified by the Transmission Provider as a Market Participant, (ii) is financially responsible to the Transmission Provider for all of its Market Activities and obligations, and (iii) has demonstrated the capability to participate in its relevant Market Activities.

Module A, section 1.184, Original Sheet No. 95.

[123] *See* Basin, *et al.* brief at 15-18, EKPC brief at 9-10, Rural Electric Cooperatives brief at 9-11.

passed through to GFA customers as a new service in Opinion Nos. 459 and 459-A.[124] In Opinion Nos. 459 and 459-A, the Commission refused to find that reliability services are new services, stating that customers taking service under GFAs presumably already receive such service as part of the firm service provided to them in their contracts.[125]

155. GFA customers argue that there is a clear distinction between the grid management services for which the Commission allowed pass-through of costs as a new service in Opinion Nos. 463 and 463-A and the charges that must be born by GFA Responsible Entities under the TEMT. They argue that Commission precedent requires that the Commission determine whether the Midwest ISO services at issue in this proceeding are already being provided under the GFAs and, if they are, that the costs should be assigned to the Transmission Owners in the first instance. Customers argue that the costs of congestion for which the GFA Responsible Entity would be responsible under the TEMT are associated with redispatch service that, according to Opinion Nos. 459 and 459-A, is presumed to be a part of firm transmission service already provided in the GFAs. Therefore, the GFA customers should not be the Responsible Entities because the transmission-owning parties to the GFAs are already obligated to provide the service which the TEMT requires GFA Responsible Entities to take and charging GFA customers directly for such service would result in impermissible double charges for these services.[126]

156. Rural Electric Cooperatives argue that a GFA customer takes service under the GFA and not the Midwest ISO's tariff. Furthermore, they argue that Opinion No. 453-A establishes the precedent that parties must negotiate an amendment to the GFA in order for a Transmission Owner to collect any additional charges.

157. Minnesota Power, Cleveland and AMP-Ohio argue that the presiding judges reached a formulistic result for each contract based on the TEMT and generic principles of Commission precedent and in so doing erred in determining the GFA Responsible Entity and GFA Scheduling Entity and inappropriately modified the contracts. They argue that the presiding judges should have reviewed each contract and, based on the assignment of rights and responsibilities under the contract, determined the appropriate

[124] Pacific Gas & Electric Company, Opinion No. 459, 100 FERC ¶ 61,160 at P 19-20, *reh'g denied*, Opinion 459-A, 101 FERC 61,139 (2002).

[125] *Id.* at P 19-22.

[126] *Id.* at P 22-26

GFA Responsible Entity and GFA Scheduling Entity.

158. EKPC argues that the only party to its GFAs that is a member of the Midwest ISO is LG&E and that shifting costs to EKPC for a decision made by LG&E is not consistent with the Commission's policy to preserve the commercial bargain between the parties to GFAs.[127] Only by designating LG&E as the GFA Responsible Entity can the GFAs be honored consistent with Commission policy. Northwestern, MMTG and others state that the presiding judges err in finding that transmission customers and load-serving entities will benefit from the Midwest ISO's Energy Markets.

159. Transmission Owners generally take exception to the presiding judges' finding that the GFA Responsible Entity should be the counter-party when the load serving entity is not a Market Participant under the TEMT. Rather than allowing the tariff definition to determine which entity should be the GFA Responsible Entity, the Commission should rely on its precedent to determine that the load serving entity should be responsible for the charges.[128] Allowing entities to shift costs to other Market Participants by delaying or failing to qualify for Market Participant status provides opportunities for gaming and is fundamentally unfair. Rather, they submit, the Commission should require Midwest ISO to amend the TEMT to require that a load serving entity must qualify as a Market Participant in order to receive grandfathered service to its load.[129] LG&E argues that as the entity making decisions that cause congestion, the load-serving entity should face the LMP price signal to encourage it to make efficient use of the grid. Otherwise, the load serving entity could harm other market participants by increasing the congestion costs of other transactions.[130]

(2) Commission Discussion

160. To the extent that parties to a GFA have agreed upon the designation of GFA Responsible Entity, we will adopt that designation to establish financial responsibility for GFAs that are subject to Options A, B or C, pursuant to settlements or the requirements of this order.

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[127] EKPC brief at 12 (*citing* Procedural Order at P 51).

[128] LG&E brief at 26.

[129] *Id.*

[130] *Id.* at 29-30.

161. To the extent that parties to the GFA have not agreed upon the designation of GFA Responsible Entity, we find that the GFA Responsible Entity should be the Transmission Owner or ITC Participant responsible for providing transmission service under the GFA. This is consistent with Opinion Nos. 453 and 453-A and section II.A.2.a of Appendix C of the Midwest ISO Agreement, which require that a Transmission Owner or ITC Participant take transmission service under the Midwest ISO Tariff in order to satisfy its obligations under a GFA, and section II.A.3.f of Appendix C of the Midwest ISO Agreement, which provides that service under GFAs will continue pursuant to the terms of a GFA. With respect to Rural Electric Cooperatives' argument that Opinion No. 453-A establishes the precedent that parties must negotiate an amendment to the GFA in order for a Transmission Owner to collect any additional charges, as we clarified in *Louisville Gas & Electric Company and Kentucky Utilities Company*,[131] Opinion No. 453-A was not intended to deny Transmission Owners the opportunity to recover from GFA customers the charges that Midwest ISO levies on Transmission Owners for service provided under GFAs or to require negotiation prior to the Transmission Owners' petitioning the Commission for change to the rates, terms or conditions of GFAs where the GFAs does not require such negotiation.

162. Our decision here is also consistent with more recent precedent cited by the presiding judges concerning the pass through of costs incurred under regional transmission provider tariffs to meet obligations under GFAs. While in Opinion Nos. 463 and 463-A the Commission found that grid management services performed by a regional transmission provider constitute new services presumed to not be provided for in GFAs (unless the GFAs expressly contemplate responsibility for the cost of such services), the costs at issue for GFAs choosing Options A, B, or C or converting to TEMT service are more extensive than grid management services performed by a regional transmission provider. Transmission usage charges, FTR debits and credits, and uplift costs are essentially redispatch costs, substantially similar to the redispatch costs associated with the reliability services at issue in Opinion Nos. 459 and 459-A. There, the Commission rejected PG&E's proposal to pass through to customers under existing firm transmission service contracts, as a new service, the reliability service costs that it incurs under the CAISO tariff to meet its obligations under the existing contracts. Rather, the Commission found that redispatch service must be presumed to be included in the firm transmission service provided in the contracts and thus does not constitute a new service.[132] Similarly, here we do not allow such costs to be charged directly to the

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[131] 101 FERC ¶ 61,182 (2002), *reh'g denied*, 103 FERC ¶ 61,104 (2003).

[132] *See* Opinion No. 459 at P 19-20.

customers under the GFAs, unless the GFA parties have specifically agreed otherwise in their joint filings. Instead, we require the transmission owner or ITC participant to bear the costs. We agree with LG&E that efficient use of the grid would be promoted if those with decision-making responsibility for transactions under GFAs were also financially responsible for congestion costs. However, that is a matter more appropriately addressed when parties seek to modify their GFAs to reflect treatment of those GFAs under the TEMT.

(b) GFA Scheduling Entity

163. With respect to determining the GFA Scheduling Entity where the GFA parties did not agree upon that designation, the presiding judges found that the TEMT's definition[133] makes clear that the GFA Scheduling Entity must be either the GFA Responsible Entity or an agent designated by the GFA Responsible Entity.[134] Accordingly, the presiding judges found that the GFA Responsible Entity has also been deemed the GFA Scheduling Entity.

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[133] The TEMT defines GFA Scheduling Entity as follows:

> a. All entities operating pursuant to Grandfathered Agreements shall designate a GFA Scheduling Entity within the time set forth in Section 38.2.5.k. The GFA Scheduling Entity shall submit Bilateral Transaction Schedules consistent with the provisions set forth herein for any sales and/or purchases of Energy pursuant to the Grandfathered Agreement.
>
> b. The GFA Scheduling Entity responsible for submitting such Bilateral Transaction Schedules shall either be the GFA Responsible Entity or a Scheduling Agent designated by the GFA Responsible Entity.

Module C, section 38.8.2, Original Sheet No. 444.

[134] Findings of Fact at P 40.

(1) Parties' Exceptions

164. Parties[135] state that the presiding judges erred in concluding that the GFA Scheduling Entity must also be either the GFA Responsible Entity or the GFA Responsible Entity's designated agent. Parties maintain that the presiding judges' decision is inconsistent with the contractual provisions for scheduling generation to load under the GFA and could create a reliability problem for the GFAs.

(2) Commission Discussion

165. Where the GFA Responsible Entity is financially responsible for the market impact costs of GFA transactions, then the GFA Responsible Entity must have the final say on the schedule that it submits into the Day-Ahead Energy Market for that transaction. To do otherwise would undermine the GFA Responsible Entity's ability to limit its costs for transactions under the GFA. For example, where a Transmission Owner is designated as the GFA Responsible Entity, the Transmission Owner should have discretion to use FTRs allocated to it through Option A treatment to limit the costs of the GFA transactions. To do this, unless it has agreed otherwise, the Transmission Owner must be able to schedule its best estimate of the GFA transactions in the Day-Ahead Energy Market and thus must be the GFA Scheduling Entity as that term is defined in the TEMT unless it agrees otherwise.

166. We note that designation of a particular GFA party as the GFA Scheduling Entity does not modify the rights and obligations for scheduling between the parties as currently contained in the GFA. Rather, the GFA Scheduling Entity is the entity that interacts with the Midwest ISO and the Midwest ISO Day 2 markets to schedule GFA transactions. If there are obligations in the GFA, where parties to the GFA provide one another with load and scheduling information, we expect continued full exchange of this type of information, whether the GFA is carved out or subject to the provisions of the TEMT. Consistent with this expectation of continued flow of schedule information between parties to the GFA, we direct all Transmission Owners and ITC Participants to update the Midwest ISO periodically as they receive changed information on the schedule for their carved-out GFA transactions. Under these directives for carved-out GFAs, the Midwest ISO will receive schedules from the Transmission Owners and ITC Participants on a day-ahead basis, as updates are provided to the Transmission Owners and ITC Participants by

[135] Basin, *et al.*, Cleveland and AMP-Ohio, EKPC, FirstEnergy, Great River, LG&E, Minnesota Power, Minnkota, Northwestern, Xcel, WPS Resources, and Alliant.

GFA parties or loads under the GFAs, and as a final update 30 minutes prior to the operating hour.

(c) Standard of Review

(1) Parties' Exceptions

167. Otter Tail, Xcel and Northwestern argue that Commission precedent requires a party to specifically state that the public interest standard applies to contract modifications and if the contract is silent as to the standard of review for contract modifications, that the just and reasonable standard applies since neither party waived its unilateral filing rights.

168. Great River, Basin, *et al.*, Minnkota, Dairyland, the Rural Electric Cooperatives, Cleveland and AMP-Ohio argue that the Findings of Fact mistakenly found the Commission could modify silent contracts under the just and reasonable standard of review. They argue that the presiding judges, in basing their findings on *Union Pacific Fuels, Inc. v. FERC*,[136] ignored subsequent appellate history that modified that ruling and held that the *Mobile-Sierra* standard would apply in such situations.[137]

(2) Commission Discussion

169. As our decision here only affects GFAs that are subject to a just and reasonable standard of review and does not affect the terms and conditions of GFAs that are either silent with respect to the standard of review or those GFAs where the parties have explicitly provided that the *Mobile-Sierra* public interest standard of review applies, we do not need to reach a decision on this issue here.

(d) The Presiding Judges' Database

(1) Parties' Exceptions

170. Basin, *et al.*, Dairyland and the Rural Electric Cooperatives argue that the Findings of Fact rely on a secret, limited, summary database created for this proceeding and that since, this database is not accessible by the parties, they are unable to review or effectively challenge the information used to formulate the Findings of Fact. Basin, *et al.*

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[136] 129 F.3d 157 (D.C. Cir. 1997).

[137] *See* Texaco Inc v. FERC, 148 F.3d 1091 (D.C. Cir. 1998).

state that basic administrative law principles require that the database be made publicly available and that the parties be granted sufficient time to evaluate the information before the Commission makes any decision.

171. Basin, *et al.* further argue that the data summaries contained in Attachment A and B to the Findings of Fact represent an attempt to force complex contractual agreements into a simple template, and, consequently, these summaries are incomplete and inaccurate characterizations of the terms and conditions of the contracts. Therefore, Basin, *et al.* argue that the Commission cannot rely upon only these summary sheets when making decisions about individual GFAs, or GFAs as a group.

(2) <u>Commission Discussion</u>

172. The presiding judges stated that the information in the database is available for use by the Commission's Office of Markets, Tariffs and Rates and explain that a public version of these records was attached to the Findings of Fact.[138] This implied that the database contains additional information or calculations not disclosed in the public version. However, Attachments A and B to the Findings of Fact reflect all of the information that the presiding judges provided to the Commission. The Commission and staff considered the text, Attachment A and Attachment B of the Findings of Fact, but also conducted their own contract-by-contract analysis using the full record for each GFA in this proceeding. The database does not contain, and so the Commission did not consider, any information not disclosed in the Findings of Fact or included in the record. Therefore, any concerns regarding consideration of non-public information in the database are unwarranted.

(e) <u>Due Process</u>

(1) <u>Parties' Exceptions</u>

173. LG&E argues that the trial schedule in this case deprived the parties of due process. Citing the Commission's Web site, LG&E argues that the Commission's standards for a simple case allow for 19.5 weeks from the date of the order designating a presiding judge to the date of the hearing, but that the Commission allowed only four weeks. During these four weeks, the parties were required to conduct settlement negotiations and prepare requests for rehearing of the Procedural Order. Additionally, since the GFA testimony was to be filed on Friday, June 25, 2004, for a hearing to be held starting Monday, June 28, 2004, LG&E states that it did not have adequate time to

[138] Findings of Fact at P 32.

conduct meaningful discovery or trial preparation as to the issues raised in the filed testimony. Therefore, there was insufficient time to develop an adequate record of the case. LG&E adds that the hearing was based on a conditionally-approved TEMT, which could still change. LG&E argues that the Commission did not provide any justification for the trial schedule, except that the Commission and the Midwest ISO are in a rush to allocate FTRs in October.

(2) Commission Discussion

174. We are not persuaded that the hearing schedule in this case harmed LG&E or any other hearing participant. Although LG&E claims that there was insufficient time to develop an adequate hearing record, it does not explain what aspects of the hearing record are inadequate, or specifically how the hearing schedule harmed LG&E.

175. We reject LG&E's argument that the Commission should have allowed at least 19.5 weeks between the date the Presiding Judges were designated and the beginning of the hearing. The portion of the Commission's Web site that LG&E cites notes that the time standards for hearings "were designed to process cases as quickly as possible, consistent with due process and the Commission's requirement for a full and complete record."[139] Shorter or longer periods for discovery are permissible, as the case requires.[140] And while the standard length of time for a simple case is 19.5 weeks, nothing limits the Commission's authority to set whatever length of time it deems appropriate.[141]

176. Further, the Commission provided numerous procedural safeguards to streamline and simplify the process of discovering GFA information. The Procedural Order specified that the hearing should be narrowly focused in order to facilitate discovery of

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[139] Processing Time Standards for Hearing Cases, http://www.ferc.gov/legal/admin-lit/time.asp.

[140] *See id.*

[141] The notice or order establishing hearing is required to describe: (a) the authority and jurisdiction under which the hearing will be held; (b) the nature of the proceeding; (c) certain procedural dates; (d) the name of the presiding officer, if known; and (e) any other appropriate matter. *See* 18 C.F.R. § 385.502(b) (2004). The Commission's Web site acknowledges that the Commission may change the standard timeline. *See* Summary of Procedural Time Standards for Hearing Cases, http://www.ferc.gov/legal/admin-lit/time-sum.asp ("These times standards [*sic*] apply unless the Commission order directs otherwise.").

well-defined GFA information that the Commission needed to complete the record for the instant order.[142] The Procedural Order allowed parties to avoid the Step 2 hearing entirely by agreeing to their GFA information and filing it, jointly, with the Commission before the hearing began.[143] It also allowed parties to agree on their GFA information during – or even after – the hearing, to withdraw from the proceeding and to submit their own resolution of any disputes regarding GFA information.[144] These safeguards allowed the parties a continued opportunity to determine the information in a cooperative, rather than an adversarial, setting.

(f) <u>Standard of Conduct</u>

(1) <u>Party Exception</u>

177. LG&E argues that the presiding judges erred in finding that the testimony of and LG&E witness, Charles Freibert, Jr., violated the independent functioning requirement in the Commission's Standards of Conduct.[145] LG&E asserts that since its witness was testifying to public, non-transaction-specific information in a public forum, his testimony should not have been precluded based on the independent functioning requirement. Furthermore, LG&E states that Charles Freibert, Jr. is the Director of Energy Marketing at LG&E and does not conduct transmission system operations; therefore, he is not a transmission function employee.

(2) <u>Commission Discussion</u>

178. The Standards of Conduct govern the relationship between transmission providers and their affiliates to prevent transmission providers and their affiliates from using non-public transmission information to compete unfairly with non-affiliates.[146] Among the mechanisms used to prevent unduly discriminatory treatment are requirements that transmission function employees function independently from the affiliate and not share

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[142] *See* Procedural Order at P 68, 76.

[143] *See id.* at P 69-70.

[144] *See id.* at 77.

[145] *See* Standards of Conduct for Transmission Providers, Order No. 2004, 68 Fed. Reg. 69,134 (2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), *order on reh'g*, Order No. 2004-A, 69 Fed. Reg. 23,562 (2004), *order on reh'g*, Order No. 2004-B, 69 Fed. Reg. 48,371 (2004).

[146] Order No. 2004 at P 15.

or provide access to non-public information.[147] A principal purpose is to prevent the sharing of non-public information with an affiliate that would give that affiliate an advantage over a non-affiliate. However, Order No. 2004 allows transmission providers and their affiliates to share with their marketing and energy affilliate, among other personnel, senior officers and directors who do not engage in day-to-day transmission functions.[148] If Mr. Freibert's testimony was limited to public, non-transaction specific information, then his knowledge and his testimony did not violate the independent functioning or the information access provisions of the Standards of Conduct. However, based on the record before us, it is unclear whether the testimony reflected only such public information or not. On the other hand, the presiding judges found, and we agree, that most of the testimony stricken from the record was outside the scope of the six questions, and the remaining information is not necessary to the Commission's decision.[149]

(g) GFA Nos. 205, 206, 207, 267, 268, and 269

179. GFA Nos. 205, 206, 207, 267, 268, and 269 (Ludington GFAs) represent four agreements that pertain to the Ludington Hydroelectric Pumped Storage Plant (Ludington Plant). The Ludington Plant, with a total generating capability of 1,872 MW,[150] is owned and operated jointly by Consumers and Detroit Edison.[151] GFA Nos. 205 and 269 are the same contract and contain both the Ownership and the Operating Agreement for the Ludington Plant. GFA Nos. 206 and 267 are the same contract, the Project Transmission Facilities Agreement for the Ludington Plant. The Project Transmission Facilities Agreement provides for service over the transmission facilities of Michigan Electric Transmission Company, LLC (METC) and International Transmission Company (ITC) associated with Consumers' and Detroit Edison's interest in the Ludington Plant.[152] GFA

[147] 18 C.F.R. § 358.4(a)(1) (2004) (independent functioning requirement); 18 C.F.R. § 358.5(a) - (b) (2004) (information access and disclosure prohibitions).

[148] Order No. 2004 at P 102-04; 18 C.F.R. § 358.4(a)(5) (2004).

[149] Findings of Fact at P 50-52.

[150] Exh. DE-1, Byron testimony at 4; Exh. CEC-1, Gaarde testimony at 4.

[151] Findings of Fact at P 319.

[152] *Id.*

Nos. 207 and 268 are the same contract, the Transmission Facilities Agreement. GFA Nos. 207 and 268 deal with construction, operation, maintenance and use of certain transmission facilities related to the construction of the Ludington Plant that are no longer owned by either Consumers or Detroit Edison.[153] Parties to the Ludington GFAs agreed as to the source and sink points for the GFAs, that the cumulative maximum number of megawatts transmitted under the GFAs is 2,040 MW, and that the Ludington GFAs are explicitly subject to a *Mobile-Sierra* public interest standard of review.[154] There was no agreement as to the GFA Responsible Entity and the GFA Scheduling Entity for these agreements and thus these issues were set for hearing.

180. The presiding judges found that the Ludington GFAs are unique since they are the only GFAs that relate to a pumped storage facility in the Midwest ISO's footprint.[155] The judges also state that the Ludington Plant is transmission dependent because it requires transmission service both to deliver the output of the plant to Consumers' and Detroit Edison's load, and to deliver electricity to fuel the plant by pumping water back into the reservoir.[156] The presiding judges found that Detroit Edison and Consumers benefit from the Midwest ISO services and should both be designated as GFA Responsible Entities for the Ludington GFAs. Consistent with this finding, the presiding judges designated both Detroit Edison and Consumers as the GFA Scheduling Entities for the Ludington GFAs. Finally, the presiding judges noted that throughout the hearing process the parties have been in discussions with the Midwest ISO regarding the possibilities of altering the TEMT to accommodate the unique circumstances posed by the Ludington GFAs.[157]

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[153] Exh. CEC-1 at 7.

[154] June 25, 2004 Supplemental Joint Written Statement of Detroit Edison, Consumers, METC, and ITC at 4-5.

[155] The plant is located on the western edge of Consumers' service territory. Findings of Fact at P 324.

[156] *Id.* at 325.

[157] *Id.* at n. 124.

(1) Party Exceptions

181. Detroit Edison argues that the Findings of Fact fail to find that the unique attributes of the Ludington Plant require accommodation during implementation of the Midwest ISO TEMT. Detroit Edison states that the Ludington Plant is unique because, unlike other generating facilities, it can be dispatched very quickly, can provide load following or regulation, and 10 minute operative reserves to respond to real time contingencies, requires transmission to deliver power to the facility and transport power away from the facility, and utilizes energy limited resources. Detroit Edison states that since "the facility is dispatched on a day-of or real time basis" there is no way to provide day-ahead schedules for the output of the unit that would prevent the Ludington GFA parties from paying real-time congestion costs under the provisions of the Midwest ISO TEMT.[158] Detroit Edison is concerned that this inability to provide accurate day-ahead schedules could result in significant real time congestion costs under the proposed provisions of the TEMT. Detroit Edison argues that in failing to account for the uniqueness of the Ludington Plant, TEMT's provisions do not accommodate the operating rights and responsibilities established in the Ludington GFAs.

182. Detroit Edison also argues that the presiding judges erred in suggesting that Detroit Edison should be the GFA Responsible Entity for transmission over the METC transmission system. Because the Ludington Plant is located on the western edge of Consumers' service territory, Detroit Edison requires transmission service over both the ITC and METC transmission systems in order to transport energy to the Ludington Plant for pumping and from the Ludington Plant for delivery of power to Detroit Edison's load. Detroit Edison asserts that the Commission should designate Detroit Edison as the GFA Responsible Entity for GFA transactions in the METC system and Consumers as the GFA Responsible Entity for GFA transactions using the ITC system.

183. The Midwest ISO, in its August 17, 2004 informational filing, advised the Commission of its analysis of the megawatt quantities represented by each GFA. For the Ludington GFAs, the Midwest ISO estimated the total megawatt capacity at 2,040 MW.

(2) Commission Discussion

184. In the TEMT II Order, we stated that we agreed with Detroit Edison that converting its Ludington GFA rights to FTRs presents a challenge.[159] At that time we

[158] Detroit Edison brief at 12.

[159] TEMT II Order at P 185.

stated that without sufficient detail on the current rights associated with the Ludington Plant, we could not determine whether it was reasonable to grant the Ludington GFA parties rights beyond those granted non-GFA parties in the TEMT. The instant proceeding has provided the information necessary to determine the treatment of the Ludington GFAs.

185. Since the Ludington GFA parties agree that their contracts contain a Mobile Sierra standard of review, and since they have demonstrated that their rights and responsibilities under the Ludington GFA, as well as the operations of the Ludington Plant, are unique, we grant the parties the accommodation they seek. We direct the Midwest ISO to carve these GFAs out of the Energy Markets for the remainder of the six-year transition period. We require Detroit Edison and Consumers to submit day-ahead and modified real-time schedules, as well as any intervening updates, to the Midwest ISO for each utilities' GFA transactions providing pumping energy to the Ludington Plant and for GFA transactions where power flows from the Ludington Plant to Consumer's or Detroit Edison's loads.

186. We are concerned that Detroit Edison has stated that it cannot effectively provide day-ahead schedules for the Ludington Plant. We construe Detroit Edison's comment as support for why it should not be required to pay congestion costs in the Midwest ISO's Real-Time Energy Market for transactions under the Ludington GFAs rather than a statement that it is unwilling to provide its best estimate of GFA transactions a day before they occur. We note that the scheduling requirement directed above does not have financially binding impacts for differences from the day-ahead to real time schedules for GFA transactions. We believe this addresses Detroit Edison's concern about real-time congestion costs. However, given the scheduling challenges that Consumers and Detroit Edison identify for the Ludington Plant and the fact that the Ludington Plant has a large generating capability and its operation has significant reliability impacts on the grid, we will require additional coordination with the Midwest ISO. In this respect, we direct Consumers and Detroit Edison to share information with the Midwest ISO about restrictions on the Ludington Plant's use and any daily and hourly contingencies the units face.

187. We find that the Midwest ISO has overestimated the peak megawatt capacity associated with these GFAs. The joint filings show that when the plant is a load, pumping water back into the upper reservoir, 2,040 MW flows from Consumers and Detroit to the Ludington Plant.[160] However, historical data shows that the plant did not

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[160] July 25 Supplemental Joint Written Statement Regarding GFA Nos. 205, 206, 207, 267, 268, 269 at 5. At times, usually during periods of low system demand, a pumped storage plant is a load, and draws power from other generators to pump water (continued)

pump during peak periods of the last three years.[161] Since both Consumers and Detroit state that the generating capability of the plant is 1,872 MW, and historical data shows that the maximum output on peak has been significantly less that the generating capability,[162] we find that the Midwest ISO should carve out on-peak capacity from its FTR model equal to the generating capability of the plant for the Ludington GFAs prior to its initial FTR allocation. The Midwest ISO should carve out off-peak capacity for the Ludington GFAs equal to the pumping load, 2,040 MW.

(h) GFA Nos. 297 and 308

188. Central Power Electric Cooperative (CPEC) and East River Electric Cooperative (EREC) supply wholesale power to their member cooperatives from fixed allocations of hydropower from the Western Area Power Administration. GFA No. 297 is an integrated transmission agreement between CPEC and Otter Tail that allows each entity to provide transmission to the other entity over shared facilities. GFA No. 308 is an interconnection and transmission service agreement between EREC and Otter Tail under which Otter Tail provides transmission service to two of EREC's member cooperatives. The presiding judges found that, based on certain findings of fact, the TEMT should not apply to GFA Nos. 297 and 308 and that the two contracts should be removed from the proceeding. The presiding judges based this finding, on, among other things, the facts that: (1) CPEC, party to GFA No. 297, and EREC, party to GFA No. 308, are non-jurisdictional entities; (2) all of CPEC's and EREC's GFA loads are served from generators located in the WAPA control area; and (3) CPEC and EREC's loads served under these two GFAs are dynamically scheduled or short interval scheduled out of Otter Tail's control area. In the alternative, should the Commission decide that the TEMT should apply to these GFAs, the judges found that (1) the *Mobile-Sierra* public interest standard of review applies to both of these contracts; (2) the GFA Responsible Entity for GFA Nos. 297 and

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back into its upper reservoir. Because pumping is not perfectly efficient, there are performance losses associated with moving water to the upper reservoir. Thus it takes more power to move the water to the upper reservoir than is created when the plant is releasing water to generate power.

[161] July 9 Supplemental Joint Written Statement Regarding GFA Nos 205,206,207, 267, 268, 269, Attachment A.

[162] *Id.*

308 is Otter Tail; and (3) the GFA Scheduling Entity for both GFAs is WAPA acting as an agent for Otter Tail.

(1) Parties' Exceptions

189. Basin, *et al.* agrees with the Findings of Fact that GFA Nos. 297 and 308 should not be subject to the TEMT; however, it disagrees with the individual findings if the Commission decides to include the GFAs under the TEMT. Basin, *et al.* states that, as to GFA No. 297, Otter Tail should be the GFA Responsible Entity, WAPA should be the GFA Scheduling Entity, and 150 MW is the maximum under the contract; as to GFA No. 308, Otter Tail should be the GFA Responsible Entity, WAPA the GFA Scheduling Entity, and approximately 16 MW is the maximum amount transmitted under the contract. Basin, *et al.* also asserts that the TEMT should not apply to GFA No. 297 because Otter Tail did not transfer to the Midwest ISO the portion of Otter Tail's facilities that is required to serve the CPEC loads.

(2) Commission Discussion

190. We find that Otter Tail provides transmission under GFA No. 308, much like a through-and-out transaction. For this reason we find that GFA No. 308 cannot be removed from this proceeding. In the normal course of operation, since EREC's load is dynamically scheduled out of Otter Tail's control area, Otter Tail provides wheeling across its system (but does not provide ancillary services or imbalances under this contract). This does not mean that the flows over Otter Tail's transmission lines cannot in the future cause congestion that impacts the Midwest ISO's SCED in its Day-Ahead and Real-Time Energy Markets. We also find that GFA No. 308 is silent as to the standard of review as both parties agree that it contains no provisions for unilateral changes to the contract. For this reason, consistent with our finding on GFAs that are silent as to the standard of review, we direct the Midwest ISO to carve this contract out of the Energy Markets for the duration of the transition period. We affirm the presiding judges' alternative finding for the source and sink points and find that the maximum number of MW transmitted pursuant to the GFA is the highest number of the three years of historic data, 16.2 MW.

191. We note that EREC has pledged to give its load and scheduling information to the Midwest ISO.[163] We also note that Otter Tail does not serve load under GFA No. 308. For this reason we will direct EREC, rather than Otter Tail, to provide the day-ahead scheduling information transactions under this GFA, consistent with our discussion

[163] Findings of Fact at P 223.

above. Finally, we expect that EREC will register with the Midwest ISO as a market participant so that if it ever needs to purchase energy in the Midwest ISO market, for an emergency or otherwise, it will be subject to the TEMT for those transactions.

192. We also find that GFA No. 297 cannot be removed from this proceeding at this time. Since we do not have sufficient information to determine whether transmission service under GFA No. 297 is provided over Midwest ISO facilities, we set this GFA for hearing as described below. We also find that GFA No. 297 is silent as to the standard of review as both parties agree that it contains no provisions for unilateral changes to the contract. For the purposes of the interim period, as also described below, we direct that GFA No. 297 be carved out of the Energy Markets.

(i) GFA Nos. 273, 284, 297, 306, 309, 311, 313, 314, 316, 317, and 450

(1) Parties' Exceptions

193. Minnkota asserts that it does not transmit power over Midwest ISO facilities under GFA Nos. 284, 309, 311 (a duplicate of 273), 313, 314, 316, 317, and 450 because its rights to use the facilities identified in the GFAs were never transferred to the Midwest ISO. It states that it does not use the Midwest ISO controlled grid to serve its load under the GFAs. Therefore, Minnkota argues the neither the Midwest ISO nor the Commission nor any other party can lawfully impose TEMT costs on Minnkota.

194. Otter Tail argues that the Findings of Fact should have excluded GFA Nos. 297, 306, 309, 311, 313, 314, and 317 since these are integrated transmission agreements that govern the joint construction and operation of transmission facilities and the non-public utility parties' use of their own transmission rights. Furthermore, Otter Tail states that it transferred to the Midwest ISO only those rights it controlled, (*i.e.*, transmission rights to move its power to its load), not those rights it did not control (*i.e.*, transmission rights of the non-public utility counter-parties[164] to move power over the integrated transmission facilities to their loads). Therefore, since these entities will not be receiving Midwest ISO service, these agreements should have been excluded. Basin, *et al.* concurs with Otter Tail that the TEMT should not apply to GFA No. 297 because Otter Tail did not transfer to the Midwest ISO the portion of Otter Tail's facilities that is required to serve the CPEC loads.

[164] CPEC, GRE and Minnkota.

195. Minnesota Power argues that GFA Nos. 316 and 450 are not transmission agreements and were incorrectly included in this proceeding. Minnesota Power states that GFA Nos. 316 and 450 are interconnection agreements that do not provide for transmission service, but require the parties to take service under a separate agreement and that it takes transmission service under the Midwest ISO Tariff for the paths covered by these agreements. Minnesota Power argues that any interpretation of these agreements would result in a direct violation of Order No. 888.

(2) Commission Discussion

196. We do not have sufficient information in the record before us to determine whether transmission service under the above-listed GFAs is provided over Midwest ISO facilities or whether these contracts should be excluded from this proceeding and not be considered GFAs for purposes of the Energy Markets. It may be that some of these GFAs will impact the Energy Markets, while others will not. Importantly, input from the Midwest ISO on whether control of the facilities in question was transferred to the Midwest ISO (as Transmission Provider) is lacking. Therefore, we will set them for further hearing and settlement judge procedures. In this further proceeding, the parties can address the threshold issue of whether the service provided under these contracts will impact operation of the Energy Markets. In addition to this issue, parties should also address which facilities have been transferred to the control of the Midwest ISO and the six pieces of information the Commission asked for in Step 1, as described in the Procedural Order. This information is important in order to determine if these contracts should be excluded and, if not, how they should be treated under the TEMT. While the Midwest ISO has not commented specifically on these GFAs, its input is vital for us to determine the correct treatment of these contracts. Therefore, we expect the Midwest ISO to actively participate in this hearing.

197. However, while we are setting these matters for a further trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[165] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[166] The

[165] 18 C.F.R. § 385.603 (2004).

[166] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their (continued)

settlement judge shall report to the Chief Judge and the Commission within 60 days of the date of this order concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

198. Finally, we note that the Midwest ISO needs to know how to account for service under these GFAs during the interim period until these issues are finally resolved. We note that these GFAs are either silent as to the standard of review or the parties have explicitly agreed that they are subject to the *Mobile-Sierra* public interest standard of review. Therefore, consistent with our discussion above, we direct the Midwest ISO to carve each of these GFAs out of the Energy Markets.

(j) GFA Nos. 220 and 221

(1) Presiding Judges' Findings of Fact

199. Historically, EKPC has served its loads on the LG&E/Kentucky Utilities Company system from generation within its own control area. However, while there are delivery points outlined in the GFAs, these GFAs are silent on source points. The presiding judges found that the determination of whether the source points under these GFAs is unlimited, as EKPC argues, is a matter of contract interpretation that is beyond the scope of this proceeding, and is also the subject of litigation in Docket No. ER02-2560-002.

(2) Parties' Exceptions

200. EKPC argues that the Findings of Fact incorrectly conclude that the determination of whether the source points available to it under these GFAs is beyond the scope of this proceeding. EKPC asserts that it presented unrebutted evidence that the source points under their agreements are unlimited. EKPC argues that the GFAs' silence on source points indicates that it should have access to unlimited source points.

201. LG&E argues that the Findings of Fact correctly determined that EKPC has historically served its load from EKPC's own generation in its control area. Therefore, LG&E argues that the Findings of Fact should have found that the contract limits the source points to EKPC's own generator in its control area.

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background and experience (www.ferc.gov – click on Sitemap, then Office of Administrative Law Judges).

(3) Commission Discussion

202. For purposes of this proceeding, the parties to these GFAs have provided information for historic source and sink points, consistent with the Procedural Order. Since this historical data is sufficient for us to determine the proper treatment of GFAs under the TEMT. Any dispute regarding source points in these contracts in the future is, as the presiding judges correctly point out, a contract interpretation issue that is outside the scope of this proceeding. The Midwest ISO will use the historical information provided in incorporating transactions under these GFAs into the Energy Markets, depending on the standard of review.[167]

(k) GFA No. 293

203. GFA No. 293 is a long-term transmission service agreement between Northwestern and Dairyland. This contract allows each party to transmit over the others' transmission system subject to available capacity. Under this contract, the disputed transactions involve Dairyland's transmission across Northwestern's system to serve Dairyland's load in Grantsburg Wisconsin (Grantsburg load). Dairyland is not a member of the Midwest ISO, but Northwestern is. Consequently, service provided by Northwestern to Dairyland over Northwestern's facilities will be service over Midwest ISO facilities and subject to the TEMT. However, service provided by Dairyland to Northwestern over Dairyland's facilities will not be service over Midwest ISO facilities and therefore will not be subject to the TEMT.

204. The presiding judges stated that Dairyland is utilizing and deriving benefits from the Midwest ISO grid and therefore, under Commission precedent, Dairyland should be the Responsible Entity. However, the presiding judges found that since Dairyland is not a member of the Midwest ISO, Northwestern should be designated as the GFA Responsible Entity and GFA Scheduling Entity for Dairyland's use of Northwestern's system.

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[167] We note that parties agree to the standard of review applicable to GFAs Nos. 220 and 221. GFA No. 221 and the service applicable to loads in excess of base load amounts under GFA No. 220 are subject to a just and reasonable standard of review. Service applicable to base load amounts under GFA No. 220, the parties have explicitly provided, are subject to the *Mobile-Sierra* public interest standard.

(1) **Parties' Exceptions**

205. Northwestern argues that since Dairyland receives the benefits from the Midwest ISO grid, Dairyland should be the GFA Responsible Entity, even though it has not applied to Midwest ISO to become a Market Participant. Northwestern asserts that since Dairyland will benefit from the Midwest ISO Energy Markets, it should assume financial responsibility under the TEMT for its transactions under the GFA.

206. Northwestern also argues that Dairyland should be the GFA Scheduling Entity for this GFA since Dairyland is better positioned to be the GFA Scheduling Entity and has, or will have, the resources to schedule its own load. Northwestern states that its load is located in the Northern States Power Company (NSP) control area and NSP schedules for Northwestern. Northwestern also states that Dairyland operates it own control area and receives hourly load information from its load on Northwestern's transmission system that Northwestern does not receive. Furthermore, Northwestern states that Dairyland will also be scheduling its non-GFA load with the Midwest ISO, and Dairyland exchanges scheduling information with NSP regarding its load on Northwestern's transmission system. Therefore, Northwestern argues, since it is not and will not be scheduling its own load, and Dairyland will be, Dairyland is in a better position to act as the Scheduling Entity for this GFA.

207. Regarding the standard of review applicable to this GFA, Northwestern argues that Commission precedent requires parties to specifically state that the public interest standard applies to contract modifications and, if the contract is silent, the just and reasonable standard of review applies since neither party waived its unilateral filing rights. Furthermore, Northwestern argues that since GFA No. 293 has an indefinite term, only subject to termination on 48 months notification, it is likely that either party would apply for a rate change especially in light of the evolving energy markets and the need to adequately allocate costs due to changed circumstances.

208. Dairyland supports the presiding judges' finding that Northwestern should be the GFA Responsible Entity and the GFA Scheduling Entity since Dairyland is not, and does not intend to become, a member of the Midwest ISO. Dairyland contends that it does not need to take service from the Midwest ISO to utilize the transmission service it receives from Northwestern. Furthermore, Dairyland argues that the presiding judges misapplied Commission precedent by requiring the transmission customer to be responsible for charges that the GFA Responsible Entity would be obligated to pay under the TEMT.

(2) **Commission Discussion**

209. Since this contract is silent as to the appropriate standard of review and the parties still dispute which standard should apply, consistent with the approach adopted above,

this contract will be included in the group of GFAs that will be carved-out of the market. Therefore, we do not need to reach the question of which standard would, in fact, apply here; nor do we need to reach a determinations of the other disputed findings.

(l) GFA Nos. 352, 354, 365, 393, and 431

(1) Parties' Exceptions

210. MMTG argues that, contrary to the Findings of Fact, there is no factual basis for finding that the MMTG GFAs will burden the Midwest ISO's transmission system or markets or that the public interst necessitates modification of MMTG's GFAs. MMTG argues that its GFAs provide for long-term transmission service for fixed amounts of power from WAPA to specific loads under preset terms and prices. MMTG argues that transactions under these contracts are currently subject to less cost variability than market transmissions pursuant to the TEMT and that the market costs will be disproportionately burdensome to small entities such as MMTG. MMTG argues that since the total MMTG contracts are less then 25MW and individually range from 2 MW to 14 MW, maintaining the existing contract terms will not burden the Midwest ISO's transmission system to substantiate a public interest finding to substantiate modification of these contracts, even if others are modified.

211. MMTG states that contrary to the Findings of Fact, Sleepy Eye, Minnesota, did participate in the hearing through Witness Donald S. Kom's testimony that Sleepy Eye is GFA No. 393, the maximum MW transmitted under this GFA is 2.5 plus losses, that the GFA Responsible Entity should be WAPA, the source is WAPA and sink is CMMPA, and that the *Mobile-Sierra* standard of review should apply.[168]

212. MMTG agrees with the Findings of Fact that WAPA should be the GFA Scheduling Entity, but argues that WAPA, not Xcel, should be the GFA Responsible Entity for these contracts since WAPA generates and schedules the power.

(2) Commission Discussion

213. As an initial matter, GFA No. 393 was excluded from this proceeding by the presiding judges' order dated July 15, 2005. Since we are affirming this exclusion, the exceptions to GFA No. 393 are moot. For the remaining GFAs, MMTG argues that the public interest standard of review cannot be met and therefore its GFAs should be allowed to continue as before. The parties to GFA Nos. 365 and 431 have explicitly

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[168] MMTG brief at 17 (*citing* Tr. 747:24-48:14, 764:9).

provided that they are subject to the *Mobile-Sierra* public interest standard of review, and as described above, we are requiring the Midwest ISO to carve these GFAs out of the market. Therefore, we need not address MMTG's exceptions regarding these GFAs. GFA Nos. 352 and 354 are subject to a just and reasonable standard of review, and we therefore are treating these GFAs in a manner consistent with that standard, as we describe above. Thus, MMTG's argument regarding the public interest standard is moot with respect to these contracts. The relative size of the load served does not affect our determination since we must consider them in the context of the larger sub-set of non-settling GFAs subject to a just and reasonable standard of review. Finally, the exceptions related to the GFA Responsible Entity and GFA Scheduling Entity have already been addressed generically above.

(m) GFA No. 374

(1) Presiding Judges' Findings of Fact

214. GFA No. 374 involves a 20-year contract entitled "Arpin Substation Benefit Area Joint Operating, Planning and Cost Sharing Agreement" (Arpin Agreement). The parties to this agreement include Northern States Power Company – Wisconsin and Northern State Power Company – Minnesota (together, Xcel), Wisconsin Power & Light Company (WPL), WPS Resources, and Marshfield Electric and Water Company (MEWD).[169] In their Findings of Fact, the presiding judges found that, under this GFA, Xcel provides transmission service over certain Midwest ISO-controlled facilities to WPL, WPS Resources, and MEWD for service to their loads in the Central Wisconsin System. They also found that WPS Resources and WPL should be the GFA Responsible Entities for their respective transactions under GFA No. 374. The parties agree that modifications to the contract are subject to the just and reasonable standard of review.

(2) Parties' Exceptions

215. WPS Resources and Alliant, on behalf of WPL, jointly filed exceptions to the presiding judges' finding that the Arpin Agreement provides for transmission service and therefore should not be excluded from this proceeding. They argue that the Arpin Agreement is a facilities support agreement that provides for an equitable sharing among WPS Resources, WPL, and Xcel, of costs associated with facilities necessary to interconnect their transmission systems and provides certain operating limitations to ensure reliable interconnected operations of the utilities. WPS Resources and Alliant

[169] Wisconsin Electric is an additional signatory, but not a party, to GFA No. 374. Exh. XES-1 at 39.

state that they take all of their transmission service over the Arpin Substation and related facilities pursuant to the Midwest ISO Tariff, and this service will be fully subject to the Midwest ISO Energy Markets. According to WPS Resources and Alliant, even before the advent of the Midwest ISO Tariff, the Arpin Agreement was not a basis for providing transmission service. They conclude that the Arpin Agreement does not provide a basis for allocating FTRs, has nothing to do with the Midwest ISO Energy Markets, and therefore, should have been excluded from these proceedings. They argue that the presiding judges excluded other similar agreements from the proceeding and should have excluded this agreement as well.

(3) <u>Commission Discussion</u>

216. The Arpin Agreement provides for interconnection of the parties' transmission systems and establishes financial responsibility for the costs of the interconnection facilities and operating restrictions on the parties in order to prevent or relieve overloading of the facilities or reduced system reliability. Xcel and WPS Resources and Alliant agree that: (1) no transmission service is scheduled under the agreement;[170] and (2) the agreement does not provide a basis for all allocating FTRs.[171] Further, the parties take all of their transmission service over the interconnection facilities under the Midwest ISO Tariff and such service will be subject to the Midwest ISO Energy Markets, including Schedules 16 and 17 of the Midwest ISO Tariff.

217. Given these facts, we find that the Arpin Agreement, as currently used in practice, does not provide for transmission service that will impact Midwest ISO's Energy Markets. However, based on the record before us, we cannot determine whether the Arpin Agreement could be used in the future to provide transmission service that will impact Midwest ISO's Energy Markets. Therefore, we will set this issue for hearing. In the meantime, for initial treatment of this GFA upon the commencement of Midwest ISO's markets, the MWs associated with this contract should be zero for the purpose of FTR allocation, and the parties should conduct no transactions under the contract, consistent with the parties' current practice to not transact under this agreement. Consistent with our findings above regarding the designation of GFA Responsible Entity and GFA Scheduling Entity where the GFA parties disagree on those designations, Xcel is the GFA Responsible Entity and GFA Scheduling Entity. We note that these

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[170] *See* WPS Resources and Alliant brief at 14; Xcel's July 21, 2004 response to WPS Resources Late-Filed Testimony at 5.

[171] *See* WPS Resources and Alliant brief at 10; Xcel's July 21, 2004 response to WPS Resources Late-Filed Testimony at 8.

designations will be of no practical effect for the time being as no transactions will take place under, and no FTRs will be associated with, this GFA.

6. Other Commission Findings

218. We affirm and adopt all of the orders issued by the presiding judges that excluded, with the Midwest ISO's concurrence, certain GFAs from this proceeding.[172] We will address whether these and other GFAs should be included in Attachment P to the Midwest ISO Tariff in the last section of this order.

219. Given the total number of GFAs at issue in this proceeding, the number of filings related to each GFA, and the total amount of data involved in this proceeding, we do not address in the body of this order every issue related to each GFA and the information submitted. To the extent we do not specifically address in the body of this order a concern raised about a particular GFA, our determination on the issue is contained in the information listed in Appendix B to this order. Appendix B outlines our findings regarding the maximum number of megawatts as well as the responsible entity and the scheduling entity for each GFA. To the extent this information is the same as reported in the Findings of Fact, we adopted the presiding judges' findings. To the extent that information differs from that reported in the Findings of Fact, we adopt the finding listed in Appendix B to this order. Where information in Appendix B differs from the Findings of Fact or from the information in the joint filings submitted by the parties, we have included an explanation of our rationale for each such Appendix B finding. We also adopt the source and sink information as reported in the Findings of Fact and those that were agreed to in jointly filed templates.

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[172] These include GFA Nos. 1,10, 13, 15, 18, 21, 22, 23, 24, 25, 26, 27, 32, 33, 37, 38, 40, 42, 43, 44, 45, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 93, 99, 113, 114, 115, 116, 117, 118, 119, 120, 121, 122, 123, 124, 125, 126, 127, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 138, 139, 140, 143, 148, 149, 150, 151, 153, 154, 155, 156, 157, 158, 160, 180, 181, 184, 187, 191, 193, 194, 195, 196, 197, 198, 199, 201, 202, 203, 204, 208, 217, 218, 226, 227, 228, 229, 230, 231, 232, 233, 234, 235, 236, 237, 238, 239, 240, 241, 242, 243, 244, 245, 246, 247, 248, 249, 250, 251, 252, 253, 258, 259, 260, 261, 262, 263, 264, 265, 270, 271, 272, 275, 276, 277, 278, 279, 280, 281, 282, 283, 287, 288, 290, 292, 294, 295, 296, 298, 299, 301, 303, 305, 307, 310, 312, 315, 319, 322, 325, 326, 327, 328, 329, 330, 339, 340, 345, 348, 349, 350, 351, 353, 356, 380, 393, 396, 397, 398, 400, 402, 404, 408, 429.

220. As to the finding required for maximum number of MW transmitted pursuant to each GFA, we adopt a generic approach if the GFA has no stated MW amount. For contracts for which three years of historical data is available, we find that the largest capacity figure in the three-year period is the correct number to use for the maximum MW transmitted. We believe this finding errs on the side of conservative treatment of the GFAs and best preserves the bargain inherent in GFAs that do not contain stated capacity. We direct the Midwest ISO to use the "Maximum MWs Transmitted Under GFA" stated in Appendix B, along with the source and sink information provided in the Findings of Fact and the jointly filed templates, to account for these GFAs in its model developed for the initial FTR allocation. More specifically, when accounting for GFAs in its FTR model, the Midwest ISO should use these capacity amounts: (1) as the upper limit for allocating FTRs to GFA parties whose contract has a just and reasonable standard of review and who select Option A; (2) as the upper limit for GFA transactions that are carved out of the Midwest ISO markets; and (3) as the capacity reserved under the three options for settling GFA parties. Although the Midwest ISO, in its proposal to incorporate the GFAs, proposed that the GFAs file "[t]he source and sink points applicable under the Grandfathered Agreements,"[173] we believe that the Midwest ISO may require more detailed information regarding the capacity between nodes to be reserved for the GFAs given the level of detail in its system model. Also, we believe that the Midwest ISO may require historical capacity used on a seasonal basis in order to model the GFA usage on a seasonal basis. We therefore direct parties to the GFAs, working within the findings listed in Appendix B to this order, to timely provide more detailed data at the request of the Midwest ISO. Parties that do not comply with such a request risk having a smaller number of MW or inappropriate nodes set aside for their transactions under their GFAs when the Midwest ISO begins allocating FTRs this October. We also note that parties to GFA No. 409 provided MWh usage. We direct these parties to provide to the Midwest ISO the maximum integrated hourly megawatt value for power actually transmitted pursuant to GFA No. 409 during the last three years.

221. Where more than one GFA covered the same service, we only reported the megawatts once to avoid-double counting. The notes for these GFAs will list the related GFA numbers.

222. If parties agreed that the contract was subject to a mixed standard of review, *i.e.*, some parts of the contract are subject to a just and reasonable standard and other parts subject to a public interest standard, we find that the contract is subject to a *Mobile-Sierra* public interest standard of review for purposes of classifying it for this proceeding.

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[173] Midwest ISO Tariff at 38.2.5.j(iii).

223. We direct the Midwest ISO to file revised tariff sheets, within 30 days of the date of this order, reflecting the modifications to the Midwest ISO's proposed treatment of GFAs adopted in the Procedural Order (*e.g.*, rejection of the process proposed in Module A, Section 12A, and Module C, Section 38.2.5.j) and in the instant order. These revisions should clearly identify, for each GFA, the treatment adopted in this order (*i.e.*, either converted to TEMT service or subject to a choice among Options A, B, or C pursuant to a settlement of GFA treatment approved in this order, subject to a choice among Option A or Option C because the GFA is subject to the just and reasonable standard of review, subject to a carve-out from the Midwest ISO Markets, or excluded from this proceeding).

D. Midwest ISO's FTR Options under the TEMT and Settlements

1. Background of the Midwest ISO's Proposed Options A, B and C

224. In the Procedural Order, the Commission, among other things, suspended the tariff sheets relating to the Midwest ISO's proposed treatment options for GFAs, but did not prejudge their merits.[174]

225. The Midwest ISO's proposed TEMT requires parties that did not voluntarily convert their GFAs to TEMT service to select from among three options – to remain in place for a three-year transition period that would end coincident with the six-year transition period initially approved in 1998[175] – that would determine the treatment of their GFAs in the Energy Markets.[176]

226. Under Option A, the GFA Responsible Entity would be entitled to nominate the capacity under the GFA for an allocation of FTRs. It would hold the FTRs it receives in the allocation and assume responsibility for credits, debits, rights and responsibilities

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[174] Procedural Order at P 3.

[175] *See* Formation Order at 62,167, 62,169-70.

[176] *See* Module C, Section 38.2.5.j, Original Sheet No. 402. All three options for unconverted GFAs would require the parties to submit to the Midwest ISO the following GFA information: (1) the name of the GFA Responsible Entity;[176] (2) the name of the GFA Scheduling Entity; (3) the source and sink points applicable to the GFA; and (4) the maximum megawatt capacity permissible under the GFA.

associated with those FTRs. The Midwest ISO would assess congestion charges and the cost of losses for all transactions under the GFA.[177]

227. Option B provides that the GFA Responsible Entity will not nominate or receive FTRs.[178] The Midwest ISO will charge the GFA Responsible Entity the cost of congestion for all transactions pursuant to the GFA, but – if the GFA Scheduling Entity submits the bilateral transaction schedule a day ahead, in keeping with section 39.1.4 – the Midwest ISO will credit back to the GFA Responsible Entity the costs of congestion resulting from day-ahead schedules that the GFA Responsible Entity clears in the day-ahead market.[179] The Midwest ISO will also charge the GFA Responsible Entity the cost of losses for all transactions under the GFA, then – as before, if the GFA Scheduling Entity has timely submitted a conforming schedule for the GFA – credit back to the GFA Responsible Entity the difference between marginal losses and system losses at the GFA source and sink points.[180]

228. Market Participants that select Option C will neither nominate nor receive FTRs. Instead, the GFA Responsible Entity will pay marginal losses and the cost of congestion for all transactions pursuant to GFAs without receiving reimbursements as in Option B. However, the GFA Responsible Entity will receive an allocation of excess marginal losses revenue based on their share of the marginal losses pool.[181]

229. Market Participants with GFAs that select Option A convert their rights to transmission service under the GFA to Candidate Financial Transmission Rights (CFTRs)

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[177] *See* Module C, section 38.8.3.a, Original Sheet Nos. 445-46.

[178] *See* Module C, section 38.3.3.b.i, Original Sheet No. 447.

[179] If a revenue inadequacy results, the Midwest ISO will compensate the GFA Responsible Entity for the costs of congestion by assessing debits on all Market Participants on a *pro rata* basis. *See* Module C, Section 38.8.3.b.ii, Original Sheet Nos. 448-50.

[180] The TEMT states that the Midwest ISO will determine the difference between marginal losses and system losses "on an equitable basis." Module C, section 38.8.3.b.iii, Original Sheet No. 451. The Midwest ISO further notes that this mechanism will be different from the mechanism used to refund over-collections of loss revenues to parties to non-GFA transactions. *See* Transmittal Letter at 14.

[181] *See* Module C, section 38.8.3.c, Original Sheet Nos. 452-53.

obligations.[182] The Midwest ISO has proposed to make CFTRs available based on a multi-tiered allocation/nomination methodology. Parties with FTRs granted under Option A will be considered along with parties converting existing OATT service to FTRs in the allocation.[183] Option B GFAs will have obligation FTRs corresponding to the points of injection and withdrawal in the GFA modeled in the FTR allocation; these FTRs will have priority in the tiered allocation process.[184]

230. The Midwest ISO submitted the direct testimony of Dr. William Hogan with its March 31, 2004 TEMT filing. Dr. Hogan discusses the merits of the GFA options that the Midwest ISO proposes throughout his testimony. Numerous intervening filed parties responses.

231. Dr. Hogan describes Option A as the next best option to full conversion to the TEMT, as GFA transactions would receive the same treatment as non-GFA transactions regarding scheduling and transmission usage charges, including congestion and marginal losses. The main distinction he notes is that the transmission customer who selects

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[182] *See* Module C, section 43.1.2.a, Original Sheet No. 605.

[183] According to Module C, section 42.2.4, Original Sheet Nos. 613-625, Market Participants under existing Midwest ISO Tariff service are eligible to nominate FTRs up to the total of forecast peak load served under network integration transmission service and the total MW in existing point-to-point transmission service. The GFA holders that select Option A will jointly nominate FTRs with these other Market Participants. All entities with CFTRs will be allowed to nominate a percentage of their total eligible quantity in four cumulative tiers: up to 35 percent in Tier I, 50 percent in Tier II, 75 percent in Tier III, and 100 percent in Tier IV. FTRs not awarded in one tier can be renominated in the next tier. Following Tiers I and II, nominated FTRs that would have been feasible if another party had nominated a base-load FTR that provided needed counterflow can be restored through the assignment of counterflow FTRs to the latter party as listed in Module C section 43.2.5, Original Sheet Nos. 626-629. We note that some TEMT-FTR allocation rules were modified in the TEMT II Order.

[184] CFTRs equal to 100 percent of the full MW quantity of the Option B GFAs are automatically included in Tier I, and, although the Midwest ISO will not actually issue FTRs to the GFA holders that select Option B, they must account for them when conducting the simultaneous feasibility test. FTRs allocated to Option A GFAs may also be nominated in addition to the Option B GFAs up to the tier I cap, but where the Tier I cap is exceeded, only Option B GFAs are accepted and the size of the nomination eligibility in subsequent tiers is reduced accordingly.

Option A is getting a "one-year taste" of voluntary conversion while retaining its right to pick from among the other options in later years of the transition period.

232. Dr. Hogan describes Option B as premised on the idea of making GFA parties financially indifferent to the LMP-based charges for congestion and marginal losses in the Day-Ahead Energy Market, provided they comply with scheduling requirements. Under Option B, the transmission rights contained in the GFA are in effect accommodated as firm service through the Midwest ISO's security-constrained economic dispatch. The Midwest ISO will keep the GFA financially indifferent to the costs of congestion by crediting the GFA transaction at settlement as though the scheduling party had a perfectly matching set of FTRs, thus providing a perfect hedge. To achieve the effect of charging the GFA average, rather than marginal, losses, the Midwest ISO would rebate the difference between the actual marginal losses included in the transmission usage charge, and the Midwest ISO's calculation of average losses. Dr. Hogan notes that it is not clear how the Midwest ISO will implement this marginal loss rebate provision, but nevertheless concludes that it will provide a "substantial benefit" to parties that choose Option B.

233. Dr. Hogan further discusses significant additional benefits for GFA parties that could be achieved under Option B through scheduling provisions that negate the "use-it-or-lose-it" feature of the physical transmission right. He concludes that the GFA customer would have a strong incentive under Option B to schedule all of its physical rights in the Day-Ahead Energy Market whenever it expects congestion in the Real-Time Market. Then, in real-time, if the congestion materializes as planned, the GFA customer incurs no cost for the schedule and is in effect paid to reduce its schedule in the Real-Time Market to match its actual power flow. The Transmission Owner has shifted its redispatch obligation onto the Midwest ISO. Dr. Hogan states that the risk that the congestion cost would reverse from the GFA's expectation would be rare and, on average, the GFA should benefit from the value of the implicit FTR. To minimize the side effects of Option B on other Market Participants, Dr. Hogan asserts that it is essential for the Commission to allow virtual bidding for all parties including GFAs.

234. Dr. Hogan characterizes Option C as a reasonable approach to minimize the risks that the GFA Responsible Entity would assume under certain generation/load configurations if they were required to accept counter-flow FTRs under the Midwest ISO's FTR allocation rules.

(a) <u>May Comments on the Midwest ISO's March 31, 2004 TEMT Filing</u>

235. Basin, *et al.* support the use of Option B and argues that the Commission should resist other intervenors' assertions that the Commission should reject or modify

Option B. Likewise, they argue that the Commission should not agree with the testimony of Dr. Hogan, where it discusses Option B, because it ignores important benefits that Option B provides to GFA and non-GFA customers. Basin, *et al.* asserts that Option B provides benefits to the overall market by reducing costs for GFA parties to participate in the Energy Markets. By reducing costs Option B ensures that the incentives are there for greater GFA participation, which adds to reliability and economic efficiency. Therefore, they conclude that the small amount of uplift associated with Option B is justified because it is outweighed by the overall benefits to all Market Participants.

236. Consumers argues that it is unclear if the Midwest ISO intends to fund the cost of the congestion credit through a region-wide uplift charge in sections 38.8.3.b (i) and (ii) of the TEMT. It is similarly unclear if the marginal to average loss crediting methodology will use uplift to pay for refunds between marginal and average losses in section 38.8.3.b (iii) of the TEMT.

237. Numerous commenters requested that the Commission reject some or all of the GFA options provisions because they do not do enough to preserve existing rights. For example, the NRECA does not believe that the Midwest ISO "paid heed to the Commission's preference that the 'phantom congestion' problems identified by the Midwest ISO be addressed 'in a manner consistent with contractual rights.'"[185] It asks that the Commission reject the proposal for GFAs because it does not preserve existing contract rights. The Municipal Participants argue that Option B does not hold parties economically indifferent. The Municipal Participants further state that by electing one of the options, GFA parties will forego their physical contract rights that provide benefits that they do not necessarily have to forego.

238. Dairyland argues that none of the Midwest ISO's three options does enough to ensure that GFA parties are kept financially indifferent from the impacts of the Energy Markets. Dairyland dismisses the comments of Dr. Hogan that GFA parties will be better off financially under Option B because they contend that he ignores additional risks and costs that do not exist without the Energy Markets. Instead of the Midwest ISO's proposed options, Dairyland asserts that a modified physical carve-out may be a viable option for GFAs where the Midwest ISO exempts GFAs from congestion, marginal losses, energy imbalance costs, and Schedule 16 and 17 costs in exchange for a requirement that the GFA parties register with the Midwest ISO and submit hourly schedules in the day-ahead market.

[185] NRECA May Comments at 27 (*citing* TEMT I Order at P 60).

239. Detroit Edison has similar concerns as Dairyland that none of the options is sufficient, but if forced to choose they would likely pick Option B. However, they are concerned that Option B will not provide equivalent rights to the GFA contracts Detroit Edison possesses today, particularly for its Ludington pumped storage facility.

240. Crescent Moon Utilities argue that although none of the Midwest ISO's proposed options should be accepted by the Commission, Option B does not impose unreasonable cost shifts onto third parties. In their view, Option B recognizes that there is an implicit trade-off between GFA and non-GFA parties in that non-GFA parties obtain the benefits of the Day 2 markets that would not be feasible without GFA participation. However, in order to achieve the benefits of Day 2 markets, non-GFA parties must share in uplift to maintain the benefits of the GFA contracts. Crescent Moon views Options A and C as particularly damaging because they require load to bear the costs of congestion and losses. Therefore, they recognize Option B as the least offensive of the three options to the Crescent Moon contracts.

241. Otter Tail agrees with Crescent Moon that, provided the Commission does not reject the proposed treatment of GFAs, any uplift associated with Option B should occur on a market-wide basis and not at the control area level. Otter Tail states that the Midwest ISO should amend section 42.2.4.a.ii of the TEMT to clarify that Option B will only count against a company's Tier I FTR allocation if those GFAs taking Option B are serving that company's network load. Furthermore, in the event that a company becomes a responsible entity for grandfathered service it is providing to another company, the service to that other company should not be counted against the transmission providing company's Tier I allocation.

242. Minnkota argues that Otter Tail's entry into the Midwest ISO should not abolish its agreement with Otter Tail to use the each other's higher voltage transmission facilities (and vice versa) without charge. Minnkota argues that such a change would give rise to lower quality of service and higher rates, which would not be justifiable under the "just and reasonable" or "public interest" standards. Minnkota asserts that the Midwest ISO has produced no evidence that the public interest will be harmed if Minnkota's GFAs are not modified, and therefore, the Midwest ISO's proposal must be rejected. However, Minnkota does not believe it is subject to the terms outlined in the three options, and therefore will not choose between them. Minnkota asks for protection until February 1, 2008 from congestion charges that are equal to what it enjoys today under its GFAs.

243. Minnesota Municipal protests all of the options proposed for GFAs because they view them as options that will materially change their existing agreements, especially if Option B is only available until February 1, 2008. To the extent that the terms of

Minnesota Municipal's GFA are modified, including duration, they contend that constitutes a violation of the *Mobile-Sierra* doctrine. Therefore, they request that if the options are retained that they be exempt from any financial risks caused by the new markets until the contracts expire in 2012.

244. The Midwest TDUs filed comments that state that although Option B comes closer than Option A or C to preserving existing rights under the GFAs it still fails to sufficiently honor existing contract rights. They argue that the Midwest ISO's proposal to credit back Option B customers the difference between marginal and system average losses is unclear and impossible to implement given the current lack of detail in section 38.8.3.b.iii of the TEMT. Regardless, the Midwest TDUs are clear that the system will not preserve the exact loss terms specific to the original contract under the Option B proposal. Secondly, they argue that the proposal to provide a hedge for congestion costs in Option B only applies to schedules that are not changed after the day-ahead scheduling deadline, so the GFA could be exposed to un-hedged congestion costs, which they argue is contradictory to the goal of preserving existing contract rights as stated in the prior TEMT Order. They are also concerned with the FTR allocation process and the loss application methodology applied to schedules changed after the day-ahead scheduling deadline.

245. WPS Resources believes that the GFA proposal favors GFA parties at the expense of the majority of the Midwest ISO's load. Accordingly, WPS Resources recommends that the Commission should limit GFA parties to Option A or allow all load to utilize Option B.

246. Other comments conclude that Option B extends to GFA parties financial rights beyond what they currently possess and pays for those extra financial rights through uplift. PSEG asks the Commission to eliminate Option B because it would provide benefits to transmission customers in excess of those necessary to promote their "financial indifference." However, Reliant argues that the Commission should reject the Midwest ISO's options proposal entirely because Option B forces others to bear the cost of these additional rights through uplift charges. To minimize the potential for uplift, FirstEnergy argues that the Commission should hold that the public interest requires GFA parties to abide by the TEMT. Since GFA parties will receive added benefits by transacting in the new Energy Markets, they should bear the additional costs themselves and not the Market Participants of the region.

247. Cinergy and the EPSA are likewise concerned that Option B not only preserves the benefits of the GFAs, but also expands GFA parties' benefits leaving them better off than they are today. Therefore, they argue that the Commission should reject Option B. To support their position that Option B should be rejected, Cinergy cites the testimony of the Midwest ISO's witness Dr. Hogan. Throughout his testimony, Dr. Hogan references

Option B as an option that will create added benefits for both parties to the GFA, shift costs away from the GFA parties, and distort incentives for accurate scheduling in the day-ahead market.[186]

248. Alliant comments that the options proposal grants GFA holders special treatment beyond that granted to OATT service that will result in large cost uplifts and economic inefficiencies. It recommends that GFAs should be treated in the same manner as network and point-to-point transmission service contracts. If the Commission does not adopt that methodology, it recommends that the Midwest ISO not allow nominations of FTRs for Option B to exceed the tier I limit to minimize the amount of prorating of FTRs in later tiers.

249. OMS argues that the Commission should direct that the Midwest ISO's nomination of FTRs for retained GFAs not to exceed the corresponding tier limits. The OMS contends that if the FTRs set aside for all Option B GFAs are nominated in the first tier regardless of whether or not this exceeds the 35 percent tier limit it will likely result in FTR prorating for non-GFAs in the first tier and all parties in the second tier. If this prorating is significant, it is not clear that requiring counter-flow FTRs from base-load resources will provide sufficient FTRs to keep the congestion costs of those holding existing firm transmission rights at current levels. The OMS feels that not allowing the FTRs for Option B GFAs to exceed the tier limits more fairly uplifts the costs of allowing transmission customers to retain their GFAs rather than imposing those costs on specific transmission customers who did not cause them. In other words, it will allow for a greater cost causation connection.

250. OMS states that treating GFAs the same as other network transmission service customers is the best alternative to special treatment. However, they acknowledge that in the transition period to new markets some compromises must be made and they accept section 38.8.4 that states that the special treatment afforded GFAs in section 38.8 "shall terminate no earlier than February 1, 2008."[187] To evaluate what the effect of granting different treatment for GFAs beyond February 1, 2008 would be, they recommend that the Commission open an investigation to determine the impact of the GFAs' special treatment on other market participants and the efficiency of the Midwest ISO Energy Markets. This investigation should determine whether special treatment beyond the end of the transition period on February 1, 2008 is just and reasonable. However, the OMS notes that North Dakota, Wisconsin, Iowa, Minnesota, and Montana do not agree with an

[186] *See* Hogan testimony at 9, 16-20, 37-38, and 40-51.

[187] *See* Module C, Original Sheet No. 454.

investigation of this nature at the present time because they believe it would be premature and would undercut the stakeholder process.

251. WPPI argues that designating long-term firm service under the OATT for network resources as inferior to GFA contract service through the options proposal would be unjust, unreasonable, unduly discriminatory and anticompetitive. They argue that RTO history shows that entities that resist FERC policies and avoid RTO markets benefit in the long run. As proof they state that the recalcitrant are now in a much more secure position to meet their service obligations than those that worked with FERC to start these markets, such as WPPI. Going forward, WPPI states that the Commission needs to make it clear that utilities will not be punished for cooperating with FERC policy initiatives. Finally, WPPI also asks that the GFA cost protection extend for the life of the contract and not end at the 2008 deadline.

252. The WUMS Load-Serving Entities argue that they voluntarily sacrificed GFA protection under the Midwest ISO TEMT by divesting their transmission assets to American Transmission Company LLC, and as a consequence, they will be net payers of uplift under the proposed GFA optional treatment. They further argue that the Midwest ISO assumes that all parties to existing GFAs will choose to take the Option B treatment.

(b) June Comments Responding to Paragraphs 72-74 of the Procedural Order

253. If the Commission does not adopt their carve-out proposal, the Midwest ISO TOs offer two alternative proposals for GFA treatment under the TEMT. Under the first alternative proposal, GFA parties would not be subject to the congestion management provisions of the TEMT, but would pay for any imbalances based on real-time LMP prices, provided that the Commission adopts a tariff mechanism to permit recovery of the costs associated with imbalances. They propose that, if the GFA customer agrees to provide the scheduling information, the customer submits the schedule to the Midwest ISO and pays the costs of the imbalances. If the customer does not agree to provide such information, the GFA Transmission Owner submits the schedule, but the customer must then pay any imbalance costs under the proposed tariff provision.[188] A second option offered by the Midwest ISO TOs would be to maintain all the elements of the first option, except that congestion-associated deviations from day-ahead schedules would be managed under the LMP system.[189] The Midwest ISO TOs state that adopting this approach will eliminate the need to determine whether hundreds of GFAs require

[188] Midwest ISO TOs' June Comments at 23.

[189] *Id.* at 24.

modification in order to accommodate the Midwest ISO's Energy Markets.

254. In Cinergy's June Comments, it argues that Option B is harmful to third parties and must be rejected because it would excuse GFA service providers from the cost of congestion and redispatch, causing those costs to be borne by others. It explains that FTR inefficiencies will result from greater risk premiums being placed on FTR acquisition due to the reduced ability to provide a perfect hedge from day-ahead spot market impacts. Cinergy states that Option B also provides an incentive for over-scheduling, that parties could profit from, because GFA customers would receive a full rebate for all of the transmission scheduled, including unused portions.

255. In support of its positions, Cinergy submitted the testimony of Dr. Richard Tabors. Dr. Tabors concluded that the use of Option B in lieu of a physical carve-out is not a reasonable alternative because it will lead to discrimination, market inefficiencies, and reliability concerns similar to those associated with the carve-out approach. Dr. Tabors explains that GFA parties will receive a full hedge of their congestion costs, while the non-GFA parties will receive under-valued, under-funded FTRs, and a share of the uplift costs needed to credit participants that take Option B back their congestion costs and the difference between marginal and average losses. He states that FTRs will likely be under-funded and under-allocated because the Midwest ISO must estimate in its FTR allocations the amount of transmission capacity to set aside for GFA transactions to ensure they pass the SFT. To address what he describes as a "fundamental discrimination" inherent in Option B, he recommends that the congestion credit be put on par with the actual FTR value.

256. Dr. McNamara also concluded that having the Midwest ISO set aside an appropriate set of FTRs in the FTR allocation process to account for the transmission that is likely to be used by GFA transactions could result in financial advantages for GFA parties that select Option B.[190] He determined that this could occur if the Midwest ISO assigns the GFA schedules fewer or less valuable FTRs than are needed to hedge the actual GFA transmission schedules, but still credits the GFAs as if they had a perfect congestion hedge under Option B. Another scenario under Option B envisioned by Dr. McNamara is if the Midwest ISO assigns too many FTRs to the GFA schedules, it would reduce the total number of FTRs that could be allocated to other parties, making them less than fully hedged against congestion. Thus, non-GFA parties would pay for making GFA parties financially indifferent to the costs of congestion and losses. In order to mitigate the cross-subsidy affect between non-GFA and GFA parties Dr. McNamara states that the Midwest ISO must have reasonably accurate information from GFA

[190] McNamara testimony at 36.

holders about the transmission schedules they actually expect to submit. However, he cautions that some degree of cost-shifts is inevitable as estimates of transmission usage are likely to be wrong to some extent.[191]

257. FirstEnergy is concerned that the use of Option B will shift costs to the entire Midwest ISO region. It states that the region will be forced to pay for GFA's FTRs and an increase in payments for losses through uplift charges. FirstEnergy asserts that the Midwest ISO has not quantified these costs under Schedule 16 and 17, and until power actually flows under the TEMT, the Midwest ISO will not be able to estimate its costs. Similarly, it states that the costs for marginal losses will not be known until actual losses are calculated. However, FirstEnergy believes that a cost-shift of "significant proportions" could occur.[192]

258. The Midwest TDUs argue that the Midwest ISO's proposed Option B will not result in undue discrimination against non-GFA holders. They assert that LSEs must still serve their load, and therefore face real-time LMP prices if they idle their GFAs. According to the Midwest TDUs, a GFA holder, who schedules day-ahead resources that it expects to idle anticipating counter-scheduling in the real-time market, would have to pay congestion charges on those counter-schedules if real-time congestion reversed. They also assert that one problematic part of the Midwest ISO's proposed Option B is that it inappropriately loads costs onto non-GFA customers, and thus discriminates against those competing for simultaneously feasible FTRs over the same flowgates. The Midwest TDUs contends that these charges should be uplifted broadly to avoid discrimination by an unfair delegation of costs.

259. In its June Comments, the OMS asserts that Option B provides GFA participants with an opportunity for economic gain with a subsequent uplift of costs to third party market participants. It states that, by allowing sellers to bypass congested lines and schedule anticipated GFA transmission in the day-ahead market, knowing the LMP at the load will be higher than at the point of generation, the seller is forgiven any congestion costs associated with the schedule. OMS asserts that, any excess scheduled energy not used by the GFA buyer can be resold in the real-time energy imbalance market, thereby allowing the seller to reap the benefits of the higher LMP price. Thus, according to OMS, the seller is allowed to recover real-time congestion cost differences between its generation sources and the GFA load destination. Further, OMS explains that, by over scheduling in the day-ahead market, the congestion costs forgiven may amount to more

[191] *Id.* at 37.

[192] FirstEnergy June Comments at 6.

energy than is needed to fulfill the GFA, resulting in revenue shortages collected from FTRs compared to congestion costs forgiven for GFA schedules.

260. WPS asserts that the Commission should only approve Option A to limit the amount of cost shifts. It is concerned that the parties that choose Option B may not be responsible for their own excess congestion costs since, depending on the method of uplift allocation, these charges could be recovered from all other customers, including Option A customers. WPS states that, without knowing how FTRs or uplift charges will be allocated, it is unknown whether FTR revenue will be sufficient to offset congestion costs. WPS further contends that additional administrative costs associated with Option B cannot be assessed at this time. WPS stresses that allowing GFAs to operate in the Midwest ISO market, but shifting their portion of the costs to other customers, is the essence of undue discrimination.

261. LG&E asserts that the Midwest ISO's analysis fails to address the potential cost shifts associated with Options A, B, and C. Specifically, LG&E states that: (1) Option B is unacceptable because it socializes costs associated with day-ahead schedules across the Midwest ISO footprint; (2) Option C is unacceptable because it is impossible to determine its costs and benefits; and (3) Option A is problematic because under it the GFA Responsible Entity will be entitled to nominate the capacity under the GFA for an allocation of FTRs and will be subject to all Midwest ISO costs associated with the transaction. Option A may also reduce the amount of FTRs available to other parties. The potential for cost-shifting under the three options, and lack of knowledge about the GFA issues true scope, leads LG&E to the conclusion that it would be preferable to convert all GFAs to TEMT service from the outset.

(c) Commission Discussion

262. We accept the Midwest ISO's proposal for Option A treatment for GFAs as filed in section 38.8.3(a) of the TEMT.[193] We find the provisions that outline Option A are just and reasonable; as they are overwhelmingly similar to full conversion to the TEMT, which has previously been found to be just and reasonable.[194] GFA parties that select Option A will receive almost identical financial treatment as non-GFA parties in regards to scheduling, FTR allocations, and collections from the marginal losses revenue pool. In this case, we agree with the testimony of Dr. Hogan who describes Option A as virtually

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[193] *See* Module C, Original Sheet Nos. 445-446.

[194] TEMT II Order at P 3 (2004).

the same as, *i.e.*, a "next-best" option to, voluntary conversion of a GFA to TEMT service.[195]

263. We likewise accept the Midwest ISO's proposal for Option C treatment for GFAs as filed in 38.8.3(c) of the TEMT. We find that the use of Option C is an acceptable option for those parties that take it. Accordingly, we find Option C to be just and reasonable.

264. As discussed below, we find Option B to be just and reasonable for those parties that voluntarily settled prior to July 28, 2004, in accordance with the Procedural Order,[196] but Option B will no longer be available for parties that did not settle by that date. Option B was an incentive to settle and receive a hedge against congestion and marginal losses charges. It would be unfair to allow this option to those that did not settle first and waited (and even litigated) the outcome of this proceeding. We accept that GFA parties that have settled prior to July 28th may pick among the three options on an annual basis as specified in section 38.2.5(j).[197] However, we direct the Midwest ISO to revise section 38.2.5(j) to state that only parties that settled may request a change in treatment of such agreements annually from among the three options as described in section 38.8.3. Market Participants that did not voluntarily settle may request a change of treatment annually between Options A and C, but they may not choose Option B.

265. We direct the Midwest ISO to evaluate any impacts that could be caused by annual switching among the GFA options. As a result of this evaluation, we direct the Midwest ISO to file with the Commission within 60 days a proposal to clarify section 38.2.5(j) that lists the date when such switching could occur. This evaluation should especially focus on synchronizing any ability to switch among the GFA options with the FTR allocation periods to avoid any timing conflicts, such as requests for changes in treatment in between FTR allocation periods. The date to allow changes in GFA treatment to occur should coincide with the date for redistributions of FTRs. However, the Commission will not unilaterally mandate a date on which any changes in the options may occur, given the intricate nature of the FTR process and the potential need for future timeline changes.

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[195] *See* Hogan testimony at 16 and 39.

[196] Procedural Order at P 80.

[197] *See* Module C, Original Sheet No. 400.

266. We will allow GFA parties that have not currently settled on an option to choose between Options A and C, or they may convert their agreements to service under the TEMT prior to commencement of FTR nominations.[198]

267. This decision honors GFA contracts by preserving an option that maintains the principle of financial indifference through exemptions from congestion costs and any marginal loss charges above the system average, and has the added benefit of incorporating more GFAs into the Midwest ISO markets. We agree with intervenors that greater GFA participation brings greater market benefits. We also acknowledge that the use of Option B does cause uplift for all non-Option B parties. However, the extent of that uplift is mitigated by the limited amount of MW and limited number of parties that chose Option B by July 28, 2004 as discussed in the Findings of Fact.[199] Furthermore, this decision strikes the appropriate balance between encouraging GFA settlements and minimizing the potential for uplift by limiting the availability of Option B to parties that voluntarily and timely settled. In drawing this conclusion we note Dr. Hogan's testimony where he states, "Option B could undermine the incentive and efficient scheduling properties of the LMP-based Tariff, so I agree that this approach should be offered only for a defined transition period."[200]

268. We will allow the Option B treatment to continue for parties that settled prior to July 28, 2004 until February 1, 2008. In this regard, we accept the provision that the Midwest ISO will evaluate the impact that the optional treatments for GFAs have 24 months prior to February 1, 2008, and that it will make a section 205 filing 12 months prior to February 1, 2008, that details a new proposal for the treatment of GFAs after the transition periods concludes.[201] At that time we will evaluate any proposals to extend the availability of Option B. We direct that the proposal, due on or before February 1, 2007,

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[198] We note that the Midwest ISO has recently proposed to conduct their tier I FTR nominations between October 22, 2004 and October 29, 2004 in lieu of the original October 1 start date.

[199] All of the settling GFAs that may elect Option B at any one time represent approximately 7,000 MW or 6.5 percent of the Midwest ISO's 2004 peak load of 107,552 MW. Of those, GFAs representing approximately 5,500 MW, or 5 percent of the Midwest ISO's total peak load, elected Option B for their initial treatment under the TEMT. Further detail on Option B settlements is provided in the GFA settlements section of this order.

[200] *See* Hogan testimony at 54.

[201] *See* Module C, section 38.8.4, Original Sheet No. 454.

analyze the effect Option B treatment has had on the other Market Participants, including the amount of uplift that has been needed to cover the costs of congestion and the difference between marginal and average losses.

269. We acknowledge there is some theoretical risk of gaming opportunities under Option B, in particular if, under some circumstances, GFA parties that schedule day-ahead are then able to garner "congestion relief" payments in the real-time energy market and if there is a related phantom-congestion problem as referenced in Dr. Hogan's testimony.[202] However, our decision to grant the limited use of Option B is based on our finding that the possible financial impacts of such activities are outweighed by the benefits to the operations of the Day 2 market by incorporating the day-ahead scheduling under the Option B method. In this regard, we reiterate that the amount of energy associated with the GFAs that settled on Option B is currently less than 5 percent of the overall market and the amount of uplift associated with these contracts would be correspondingly small. We also note that the required IMM information report on GFA gaming behavior and GFA scheduling behavior under Market Behavior Rule 2, directed above, will help quantify the scope and impact of any such activities.

270. We disagree with the Midwest TO's that the Midwest ISO's Option B proposal to recover congestion revenue shortfalls through uplift charges is unreasonable.[203] Costs associated with making up for congestion revenue shortfalls are essentially incurred to maintain firm transmission service, similar to the costs of uneconomic dispatch incurred to maintain firm service. We note that the Commission has previously found that redispatch costs incurred to maintain service to network and native load customers were prudent and necessary to maintain reliability and that those costs are to be shared between network and native load under the Order No. 888 *pro forma* tariff.[204] That is, it is reasonable to share the cost of redispatch to maintain firm service among all firm service customers who benefit from that redispatch. Following that principle, it is reasonable

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[202] *See* Hogan testimony at 42-45.

[203] Midwest ISO TO May Comments at 15.

[204] "Tariff sections 33.2 and 33.3 clearly establish that redispatch of all Network Resources and the transmission provider's own resources are only to be performed to maintain the reliability of the transmission system, not for economic reasons. Such costs are to be shared between network customers and the transmission provider on a load ratio basis." Order No. 888-A at 12,327.

that Option B transactions share in the cost of congestion uplift associated with maintaining their firm service rights.[205]

271. We have not adopted the Midwest ISO TOs' proposed alternative GFA treatment options. Their proposal is designed to avoid trapped costs. However, our action in this order, by only requiring GFAs subject to the just and reasonable standard of review to schedule and settle their transactions under the TEMT, already avoids trapped costs.

272. With respect to the OMS proposal to limit the Option B FTR set aside to the Tier I and Tier II limits, we decline to adopt this proposal. While we understand the concern that the option may result in fewer FTRs for non-GFAs, we do not expect the impacts to be significant or widespread in light of the level of MW committing to the option.

273. Finally, we direct the Midwest ISO to reorder its tariff to eliminate a section numbering inconsistency. Section 42.2.4, Original Sheet No. 613, should be corrected to read Section 43.2.4.

2. GFA Party Settlements

274. As stated above, in the Procedural Order, the Commission strongly encouraged GFA settlements and stated that it would be receptive to GFA parties voluntarily agreeing, in settlement, to accept one of the Midwest ISO's proposed scheduling and settlement options, including Option B, for treatment of GFA transactions, or to convert their contracts to TEMT service.[206] The Commission also stated that "such settlements avoid litigation of GFA issues and further the Commission's goals in facilitating voluntary resolution of these issues prior to the start of the Midwest ISO energy markets."[207] The Commission explained that, if it approved a settlement, it did not intend to later revisit its decision when it addressed the non-settling parties' GFAs.

275. As a result of Steps 1 and 2, GFA parties settled by mutually agreeing to accept the TEMT options for GFA treatment by choosing Option A, Option B, or a combination of A and B, or, by mutually agreeing to convert their contracts to the transmission and

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[205] The pass through of costs under GFAs is addressed in the discussion regarding the designation of GFA Responsible Entity in the "Discussion Regarding the Briefs on Exceptions to the Presiding Judges Findings" section of this order.

[206] Procedural Order at P 80.

[207] *Id.* at P 82.

energy market provisions of the TEMT. Parties settled 52 contracts, representing a total of approximately 9,729 MW. In specific, 14 GFA parties chose to settle on Option A (a total of approximately 1,599 MW), including contract numbers 94-100, 188, 223, 347, 399 (which is also listed as 417), and 417-20. The 30 GFA parties choosing to settle on Option B (a total of approximately 5,247 MW) include contract numbers 34, 141, 152, 159, 182, 214, 285, 342, 343, 355, 357-59, 362, 363, 372, 373, 378, 392, 406, 412-14, 426, 441-45, and 449. The 3 GFA parties choosing a combination of Options A and B (396 MW) include contract numbers 142, 144, and 346. Finally, 5 GFA parties chose to convert their contracts to TEMT service, including contract numbers 216, 224, 324, 375, and 376 (representing 2,487 MW).

(a) Settlement Comments

276. On July 16, 2004, Cinergy filed comments contesting provisions of certain settlements that purported to adopt Option B treatment or reserved the right to select Option B.[208] Specifically, Cinergy states that Option B is unjust, unreasonable, and unduly discriminatory and that settlements adopting Option B are unlawful and can not be accepted.[209] It asserts that the Commission should not adopt Option B settlements, absent a ruling on its lawfulness. Cinergy states that the Commission should either require, as a condition for accepting the additional elements submitted in Option B settlements, that the parties strike their election of Option B, or delay ruling on the Option B settlements pending resolution of the legality of Option B. Moreover, Cinergy asserts that the lesser "fair and reasonable" standard that the Commission appeared to invoke with respect to Option B is applicable only to uncontested settlements and that for contested settlements, the standard is just, reasonable, and not unduly discriminatory, which must be supported by substantial evidence.

277. Cinergy contends that permitting parties to select Option B leads to inefficiency and reduced reliability in the market in addition to unfair cost shifting and undue discrimination. Cinergy emphasizes that Option B will result in market inefficiency because, with load tied up in GFAs, Option B would distort the TEMT energy and FTR markets and undermine the LMP-based, financial transmission rights paradigm. It also

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[208] Cinergy lists contract numbers 101-12, 182, 209, 210, 212, 214, 222, 256, 257, 266, 285, 289, 297, 308, 323, 343, 356-59, 362, 363, 389-91, 406, 413, 414, 441-43, 448, and 449, as either selecting Option B or reserving the right to select Option B.

[209] Cinergy notes that it is a party to various settlement agreements in which the parties have selected Option B, but that it does not comment on its settlements because, in each, Cinergy reserved the right to challenge the lawfulness of Option B.

stresses that Option B gives GFA parties discounts on losses, charging them the marginal cost of losses day-ahead, but then rebating the difference between their marginal and average costs, resulting in less efficient grid use and fewer incentives to invest in generation and transmission upgrades. Cinergy argues that Option B would also promote over-scheduling, which creates phantom congestion, as it allows GFA customers to schedule their full load entitlement in the day-ahead market whenever real-time congestion is anticipated. It explains that, regardless of the amount of transmission the GFA customer actually used in real-time, the GFA customer would still receive a full rebate for all of the transmission scheduled day-ahead, including the unused portion.

278. Cinergy also emphasizes that, contrary to Dr. Hogan's assumption, there is no Commission-imposed constraint to make GFA parties "financially indifferent, or *better*" to the GFA proposal.[210] It states that the Commission only required preservation of material benefits and obligations under the contract. Thus, Cinergy argues that allowing financial indifference to LMP, as Option B does, preserves more than the material benefits under a GFA because it grants GFA parties all of the benefits of a new market design and excuses them from all price signals while shifting costs to non-GFA loads. Cinergy also asserts that, contrary to Dr. Hogan's assertions, virtual bidding, while a good idea, cannot cure the flaws of Option B. Cinergy argues that Options A and C are better alternatives than Option B because Options A and C integrate the GFAs into the scheduling and settlement process and do not materially alter the rights of GFA parties. Thus, it states that Options A and C are neither inefficient nor unduly discriminatory.

279. Finally, Cinergy requests that the Commission not yet approve the settlement offer for GFA 343. It states that GFA 343 identifies the "Cinergy Hub," which is not an appropriate OASIS designation, as a source point, but does not provide for any transmission on the Cinergy system. Cinergy explains that, for such a "partial path" GFA, it is unclear how FTRs and congestion costs will be allocated between transmission taken on an open access basis, and that taken under the GFA. Instead, it states that the Commission should require submission of data sufficient to permit clear and unambiguous application of the Midwest ISO rules.

(b) Commission Discussion

280. Consistent with the discussion above, as well as the Commission's goals in facilitating and encouraging voluntary resolution of the GFA issue prior to the start of the Midwest ISO Energy Markets, we will accept all of the GFA settlements listed above,

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[210] Cinergy settlement comments at 13; Exh. MISO-5 at 48 (Hogan).

including those of parties who chose Option B.[211] We received a number of joint filings that expressed, per the Procedural Order's instructions, GFA parties' willingness to settle on one of the Midwest ISO's proposed scheduling and settlement options.[212] We interpret these settlement filings to incorporate the material terms and conditions of the TEMT, particularly section 38.8.3 thereof, and we find that these settlements are just and reasonable.

281. With respect to GFA Nos. 142 and 144, relating to service from PSI Energy, Inc. (a franchised public utility affiliate of Cinergy) to Wabash Valley Power Association, Inc., the GFA parties indicate that they select Option A treatment for certain transactions (representing 70 MW) and Option B for other transactions (representing 326 MW). However, it is unclear whether the transactions for each option are associated with one GFA, or whether the parties have selected different options for separate transactions under the same GFA. The TEMT requires that parties to a GFA select just one option for treatment of the GFA.[213] Accordingly, we will approve the settlement for GFA Nos. 142 and 144, but will require the parties to choose one option for the transactions under each GFA and notify the Midwest ISO of their selection, in accordance with the TEMT, before the commencement of FTR nominations.

282. With respect to Cinergy's argument that permitting parties to settle on Option B results in unfair cost shifting and undue discrimination, we reiterate our discussion above that the amount of energy associated with the 29 GFAs that settled on Option B is currently less than 5 percent of the overall market and the amount of uplift associated with these contracts would be correspondingly small. We also note that, initially, Option B puts settling parties (former GFAs) on the same footing as non-GFAs for purposes of scheduling and the requirement to pay for imbalances in the real-time LMP market. To ensure financial indifference, settling parties are provided protections from congestion costs. In other words, Option B eliminates scheduling preferences as a cost of uplift for congestion costs that are shared by these same parties and non-GFAs. Allocation of a share of the uplift to non-GFAs is justified since they benefit from the elimination of scheduling preferences. In this context of shared costs, and recognizing the elimination

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[211] *See* Procedural Order at P 80.

[212] *See id.* at P 69 (requiring parties to "make a simple statement in their joint filings to indicate whether or not they are willing to voluntarily convert their contract to TEMT service or settle their GFA by voluntarily accepting the Midwest ISO's treatment of GFAs.").

[213] *See* Module C, section 38.8.3, Original Sheet No. 445.

of scheduling preferences, we do not consider the cost burden associated with Option B to be unduly discriminatory.

E. Schedules 16 and 17

1. The Midwest ISO's Proposal

283. In Docket No. ER02-2595-000 the Midwest ISO proposed Schedule 16, Financial Transmission Rights Administrative Service Cost Recovery Adder (FTR Service) and Schedule 17, Energy Market Support Administrative Service Cost Recovery Adder (Energy Market Service) as mechanisms to recover from Transmission Customers, Transmission Owners and Users the costs associated with implementing and administering the FTR markets and energy markets. Among other things, the Commission accepted the proposal and set for a paper hearing the cost allocation and rate design reflected in the proposed charges in Schedules 16 and 17.

284. In the March 31 TEMT filing in this proceeding, the Midwest ISO states that the Commission's decision in the paper hearing in Docket No. ER02-2595-000 will be incorporated into the TEMT. In this proceeding the Midwest ISO proposes modifications to the Schedules 16 and 17 that were originally proposed in Docket No. ER02-2595-000. The Midwest ISO proposes to assess Market Participants the charges in Schedules 16 and 17, instead of the Transmission Customers, Transmission Owners and Users as initially proposed. Moreover, the Midwest ISO proposes other minor modifications to Schedules 16 and 17, clarifying definitions in the formulary rates and conforming the schedules to the recently filed TEMT.

285. In the March 31 Filing, the Midwest ISO proposes three options for treating GFAs from which the parties to the GFAs may select, as discussed above. The Midwest ISO states that to the extent that the Commission applies Schedule 16 and 17 charges to GFA transactions under any of the three options, the Midwest ISO supports allowing the Market Participant assessed those charges for transactions under the GFA to recover those costs in its rates.

2. Comments

286. OMS states that assigning costs on a cost-causative basis is an important concept that should be considered on an on-going basis and is essential to ensuring an efficient market.

287. The Nebraska Intervenors, non-jurisdictional vertically integrated utilities, are concerned that the Midwest ISO's market design will force them to pay the Schedule 16 and 17 charges. The Nebraska Intervenors argue that as an entity that would largely self-

schedule its resources, the Schedule 16 and 17 charges outweigh the benefits, if any, of joining the Midwest ISO.

288. Midwest ISO TOs and Basin, *et al.* state that GFA parties should not have to pay Schedule 16 and 17 charges for their GFA transactions. Multiple TDUs state that parties to GFAs that choose Option B, should not be assessed Schedule 16 costs because they will not hold FTRs. Additionally, Manitoba Hydro states that assessing Schedule 16 costs to its GFAs will undermine the economic assumptions that formed the parties' basis for committing to the agreements. If the Commission only has jurisdiction over portions of certain existing agreements, Manitoba Hydro questions how the Commission can modify portions of these agreements without altering the non-jurisdictional aspects of the agreement or undoing the bargain as a whole. Manitoba Hydro requests that the Commission clarify that Schedule 16 and 17 charges do not apply to any existing agreements involving non-jurisdictional entities to the extent that such agreements relate to energy generated in Canada and exported by Manitoba Hydro to purchasers within the U.S.

289. First Energy, on the other hand, supports the assessment of the costs of the Energy Markets to GFAs to avoid subsidization of the GFAs by non-GFA parties. FirstEnergy suggests authorizing a limited filing by the Transmission Owners for an increase in transmission rates to cover the energy market costs under the tariff.

290. Crescent Moon also states that Schedule 17 should be unbundled to avoid cross-subsidization. Specifically, Crescent Moon states that transmission-related scheduling and spot market-related costs should be unbundled and assessed to those causing those costs.[214] Crescent Moon also states that the Midwest ISO markets should stand on their own in terms of cost recovery. If a market activity fails to recover its administrative costs, it sends an important price signal to the Midwest ISO that it should restructure the offering to make it less expensive to achieve financial breakeven. To the extent that the Commission decides that GFA transactions should be subject to Schedule 16 and 17 charges, Crescent Moon states that Schedule 16 and 17 charges should be applied to GFA parties consistent with the parties' responsibilities under the GFA. AMP-Ohio states that the billing determinants for the Schedule 17 charge should be modified to include a per-bid charge to ensure that the Midwest ISO's systems are not overworked due to a high volume of bids and offers submitted by virtual traders. AMP-Ohio notes that virtual traders have stressed the systems of PJM.

[214] For example, Crescent Moon contends that self-scheduling entities and parties engaged in bilateral transactions should not be liable for spot market-related costs arguing that such parties do not benefit from those activities.

291. Detroit Edison states that its pumped storage facility is flexibly operated to alternate between pumping and generation in ways that produce optimal reliability and economic benefits. Detroit Edison contends that by imposing Schedule 17 charges on pumped storage facilities, these units could be double charged for Schedule 17 service (*i.e.*, charged for injections and withdrawals for pumping and generation).

292. Cinergy states that utilities need assurance that they will be able to recover the costs incurred under Schedules 16 and 17, particularly costs associated with service to retail customers. Many utilities operate under retail rate freezes and may be subject to trapped costs if they are not provided an alternative method to recover the costs of the Energy Markets from their customers.

3. Commission Discussion

293. The Commission agrees with OMS that cost causation is important in allocating costs and should be considered on an on-going basis. As the Commission states in the companion order in Docket No. ER02-2595-000, *et al.*, the Midwest ISO took an important initial step in unbundling market costs from its Schedule 10 ISO Cost Adder by proposing separate charges in Schedules 16 and 17 to recover costs associated with implementing FTR Service and Energy Market Service.[215] While such unbundling by the Midwest ISO will help align cost responsibility with the benefits received, the Commission recognizes that further refinement of the unbundling of the Schedule 16 and 17 charges may be appropriate after the Midwest ISO obtains operational experience.

(a) Schedule 16

294. The Commission explains in the order issued concurrently with this order, in Docket No. ER02-2595-000, that all FTR-holders benefit from FTR Service and should pay the Schedule 16 charge for the benefits provided by the FTRs. The Commission finds that GFAs choosing either Option A or Option B benefit from the FTR Service provided by the Midwest ISO for the same reasons the Commission relies upon finding that FTR-holding bilateral transactions and self-scheduling transactions benefit from FTR Service in Docket No. ER02-2595-000. These GFAs are subject to congestion costs and the FTRs act as a hedge against those congestion costs.[216] Regardless of who actually

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[215] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,235 (2004) (Schedule16/17 Order).

[216] GFAs that choose Option A hold the FTRs and GFAs that choose Option B have the Midwest ISO hold the FTRs for them.

holds the FTRs, the Option A and Option B GFAs benefit from the hedge provided by the FTRs and these GFAs should be assessed the Schedule 16 charge for that benefit.[217] The Commission believes that, as Option B simply provides an alternative hedging mechanism to holding FTRs for GFAs that are subject to the Midwest ISO Energy Markets, there should be no distinction between Option A GFAs and Option B GFAs for Schedule 16 treatment.

295. The Commission finds that carved-out GFAs should not be assessed the Schedule 16 charge. The carved out GFAs have retained their physical transmission rights and are not subject to congestion costs in the first instance. Since the carved out GFAs are not subject to congestion costs in the Midwest ISO Energy Markets, they have no need for FTRs as a hedge against congestion costs; therefore, these GFAs do not benefit from the FTR Service as the Option A and Option B GFAs do nor do these GFAs benefit like the FTR-holding, bilateral transactions and self-scheduling transactions.

296. Since Detroit Edison's GFA involving the Ludington, MI pumped storage unit is a carved out GFA, it is not subject to the Schedule 16 charge. Likewise, since Manitoba Hydro's sales into the United States are being carved out, as discussed above, Manitoba Hydro's sales are exempt from the Schedule 16 charge.

(b) Schedule 17

297. In the companion order in Docket No. ER02-2595-000, the Commission also finds that entities engaged in self-scheduling transactions and bilateral transactions should pay the Schedule 17 charge because they benefit through their use of the transmission grid which is made more reliable as a result of the security-constrained economic dispatch that the Midwest ISO will operate in its Energy Markets. In addition the markets reveal the value of congestion so that efficient means of eliminating congestion can be implemented, thereby, increasing the efficiency of the grid. In that order, the Commission also explains that the bilateral transactions and self-scheduling transactions benefit from the existence of the Energy Markets and should therefore pay the costs to establish the Energy Markets. These transactions benefit from the efficient and transparent prices resulting from the Energy Markets and the ability to use the spot markets whenever it is economic to do so. But the Commission added that even though parties to bilateral transactions and self-scheduling transactions may not be using the

[217] By contrast, Option C GFAs do not receive a FTR as a hedge. These GFAs should not be assessed the Schedule 16 because they don't receive the benefit that Option A and Option B GFAs receive.

spot market in any given hour, they benefit from, and therefore should pay for having, an energy market.[218]

298. With respect to Energy Market Service, the Commission finds that all GFA transactions should be assessed the charge for Energy Market Service in Schedule 17 regardless of whether or not they are carved out of the Midwest ISO Energy Markets. GFAs will receive the same benefits, discussed in the Commission's companion order in Docket No. ER02-2595-000, as the bilateral transactions and self-scheduling transactions from the Energy Market Service. As the courts have ruled, "upgrades designed to 'preserve the grid's reliability' constitute 'system enhancements [that] are presumed to benefit the entire system.'"[219] Similar principles apply to the cost of implementing the Energy Markets, which will produce more reliable service and more efficient Energy Markets that will benefit all transacting over the Midwest ISO grid. GFAs should pay for the benefits they receive. Likewise, non-GFA transactions should not subsidize GFA transactions.

299. The Commission agrees with Detroit Edison and concludes that Detroit Edison should be assessed the Schedule 17 charge only on its pumped storage facility's injections into the transmission system.[220] Since the extractions from the transmission system occurring when the facility is in pumping mode, are not to serve load in the traditional sense,[221] such extractions from the transmission system should not be

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[218] Schedule 16/17 Order at P 47 (*citing* Midwest ISO Transmission Owners, *et al.* v. FERC, 373 F.3d 1361, 1371 (D.C. Cir. 2004).

[219] *See* Entergy Services, Inc., 319 F.3d 536, 543 (D.C. Cir. 2003) (*citing* Western Massachusetts Electric Co. v. FERC, 165 F.3d 922, 923, 927 (D.C. Cir. 1999)).

[220] A pumped storage project is designed to meet the system's need for electricity during periods of peak demand. Such a project operates by means of two reservoirs at different elevations in close proximity to one another. During times of low energy demand other generation is used to pump water from the lower reservoir to the upper reservoir. At times of peak demand, the water is dropped back to the lower reservoir, through generating facilities, to produce power.

[221] *See* Power Authority of the State of New York, 25 FERC ¶ 61,084 at 61,265 (1983) (pumped storage is an energy storage device which takes unused off-peak energy, and stores it for peak energy use). *See also* Norton Energy Storage, L.L.C., 95 FERC ¶ 61,476 (2001) (Commission views the pumping energy not as being consumed, but rather as being converted and stored).

assessed the charge. By charging the pumped storage facility only when it is in generation mode, the pumped storage facility will be placed on the same footing as other generation. The Commission also finds that Manitoba Hydro's sales into the United States should be subject to the Schedule 17 charge just as the other GFAs, including other carved-out GFAs, are subject to the Schedule 17 charge, because they will benefit from the Energy Markets in a manner similar to any other power sales transaction.

(c) <u>Billing Entity</u>

300. In this proceeding the Midwest ISO has proposed to bill Market Participants the Schedule 16 and 17 charges instead of "Transmission Customers, Transmission Owners, Users or other entities," as originally proposed. The Commission accepts the change, to clarify which entities will be charged for Schedule 16 and 17 service, subject to further modification. Midwest ISO should modify Schedules 16 and 17 to clarify their applicability to GFA transactions consistent with our findings above and to clarify that the billing entity for GFAs subject to Options A, B or C, either pursuant to settlements or the requirements of this order, is the GFA Responsible Entity. These revisions should also reflect that the GFA Responsible Entity for GFAs subject to Option B treatment will be responsible for Schedule 16 charges for the hedge in the Day-Ahead Energy Market provided in that option. Finally, consistent Opinion Nos. 453 and 453-A, which require that the Transmission Owner or ITC Participant take transmission service under the Midwest ISO Tariff in order to satisfy its obligations under the GFA,[222] the billing entity for carved out GFAs is the Transmission Owner or ITC Participant taking transmission service pursuant to the Midwest ISO tariff to meet its obligations under the GFA.

301. The Commission has already addressed FirstEnergy and Cinergy's concerns about cost recovery from GFAs and retail load in previous orders.[223] The Commission stated that it was speculative whether states with retail rate freezes will block the recovery of any Commission-established rates, and even if states did deny recovery of Commission-established rates, any such denial would be challengeable in state fora.[224] The Commission reiterated that utilities have the opportunity to make a filing that demonstrates and supports that such costs are currently unrecoverable and should be

[222] Opinion No. 453 at 61,173.

[223] *See* Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,279 (2003), *order denying rehearing*, 106 FERC ¶ 61,337 (2004).

[224] Midwest Independent Transmission System Operator, Inc., 106 FERC ¶ 61,337 at P 14.

treated as a regulatory asset. Additionally, the Commission denied a request to generically modify GFAs because the request was based solely on the statement that there were many contracts precluding modification through unilateral filings to recover Schedule 16 and 17 charges. The Commission also stated that when the contracts do not allow modification to recover Schedule 16 and 17 charges, another option would be to seek recovery of costs incurred under Schedules 16 and 17 as new services.[225]

302. While the Transmission Owners and the Midwest ISO urge the Commission to adopt a tariff mechanism to charge GFA customers directly for Schedule 16 and 17 service, they have not made a concrete proposal identifying the GFA party that should be responsible for such costs or addressing whether or not the contracts already address responsibility for such costs. Thus, the proposal is not ripe for consideration.

F. Attachment P - Docket No. ER04-106-002

303. On May 26, 2004, the Midwest ISO submitted a compliance filing containing proposed revisions to Attachment P as directed by the Commission in its underlying order.[226] As is evident from our discussion above, the Midwest ISO's compliance filing has been overtaken by events, and so we will direct that the Midwest ISO make a new compliance filing.

304. Specifically, with respect to which grandfathered agreements should be included in Attachment P, the Commission concludes that the definition of GFAs provided in the TEMT should be utilized for determining which GFAs should be included in Attachment P. That definition, section 1.126 of the recently approved TEMT, defines GFAs as:

> An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the commission's policies. These agreements are set forth in Attachment P to this Tariff.

Thus, the Commission directs the Midwest ISO to make a compliance filing, in a new subdocket of Docket No. ER04-106, revising Attachment P.

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[225] *Id.* at P 18 (*citing* Opinion No. 463 at P 46).

[226] *See* Midwest Independent Transmission System Operator, Inc., 106 FERC ¶ 61,387 (2004).

305. Given the Commission's finding here, that the section 1.126 definition contained in the TEMT should be used to determine which agreements should be included in Attachment P, this compliance filing should not reflect any other criteria for determining whether an agreement should be included, or excluded, from Attachment P.[227] We also direct the Midwest ISO to specify for each contract listed in Attachment P the contract's treatment per the directives of this order, (*i.e.*, either converted to TEMT service or subject to a choice among Options A, B, or C pursuant to a settlement of GFA treatment approved in this order, subject to a choice among Option A or Option C because the GFA is subject to the just and reasonable standard of review, subject to a carve-out from the Midwest ISO Markets, or excluded from this proceeding).

<u>The Commission orders</u>:

(A) Transmission Owners and ITC Participants providing service under GFAs that did not settle and that are subject to a just and reasonable standard of review must choose scheduling and settlement Option A or Option C, and notify the Midwest ISO of their selection before October 1, 2004, in accordance with the TEMT, as discussed in the body of this order.

(B) The Midwest ISO is directed to carve out of its Energy Markets all other GFAs that did not settle, as described in the body of this order.

(C) The Midwest ISO's proposed Option A and Option C TEMT treatment for GFAs are hereby accepted, as discussed in the body of this order.

(D) The Midwest ISO's proposed Option B is hereby accepted for those parties that chose it prior to July 28, 2004, as discussed in the body of this order.

(E) The 52 settlements described above are hereby accepted, as described in the body of this order.

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[227] We expect that the Midwest ISO will be adding or deleting entities, based on the TEMT definition, and correcting inaccuracies. If the protestors to the earlier compliance filings still have concerns after the filing of this new compliance filing, they can raise them in response to this new compliance filing.

(F) The parties to GFA Nos. 142 and 144 are directed to choose between Option A and Option B for the transactions under each GFA and notify the Midwest ISO of their selection, in accordance with the TEMT, before the commencement of FTR nominations, as discussed in the body of this order.

(G) Parties to GFAs are directed to provide the Midwest ISO with more detailed information regarding the capacity between nodes to be reserved for the GFAs, and data regarding historical capacity used on a seasonal basis, as described in the body of this order

(H) The Midwest ISO is hereby directed to file reports with the Commission, as described in the body of this order.

(I) The Midwest ISO is hereby directed to make compliance filings, in Docket Nos. ER04-691-000 and ER04-104-000, within 30 and 60 days of the date of this order, as discussed in the body of this order.

(J) The Midwest ISO is hereby directed to make a compliance filing, in Docket No. ER04-106, within 60 days of the date of this order, providing a revised Attachment P consistent with the definition of grandfathered agreements in the TEMT, as discussed in the body of this order.

(K) The IMM is hereby directed to monitor GFA customers for gaming behavior and provide an informational report to the Commission prior to the second FTR allocation, as discussed in the body of this order.

(L) The presiding judges' Findings of Fact are hereby affirmed in part and reversed in part, to the extent discussed in the body of this order.

(M) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a further public hearing shall be held concerning GFA Nos. 273, 284, 297, 306, 309, 311, 313, 314, 316, 317, and 450. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Paragraphs (N) and (O) below.

(N) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2004), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in these proceedings within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge in writing or by telephone within five (5) days of the date of this order.

(O) Within sixty (60) days of the date of this order, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(P) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Linda Mitry,
Acting Secretary.

Appendix A

Relevant Parties Filing Protests or Comments to the Midwest ISO's March 31 Filing

Alliant – Alliant Energy Corporate Services, Inc.
ATCLLC – American Transmission Company LLC
Basin, *et al.* – Basin Electric Power Cooperative, East River Electric Power Cooperative, Inc., Central Power Electric Cooperative, Inc. and Capital Electric Cooperative, Inc.
Cinergy – Cinergy Services, Inc.
Consumers – Consumers Energy Company
Crescent Moon Utilities – Basin Electric Power Cooperative, Heartland Consumers Power District, Minnkota Power Cooperative, Inc., NorthWestern Energy, Sunflower Electric Power Corporation and the Upper Great Plains Region of the Western Area Power Administration
Dairyland – Dairyland Power Cooperative
Detroit Edison – Detroit Edison Company
EPSA – Electric Power Supply Association
FirstEnergy – FirstEnergy Service Company
Midwest ISO TOs – Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, and Central Illinois Light Co. d/b/a AmerenCilco; Aquila, Inc. d/b/a Aquila Networks (f/k/a Utilicorp United, Inc.); City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; LG&E Energy Corporation (for Louisville Gas and Electric Co. and Kentucky Utilities Co.); Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company (Wisconsin), subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest TDUs – Great Lakes Utilities, Indiana Municipal Power Agency, Lincoln Electric System, Madison Gas and Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, Upper Peninsula Transmission Dependent Utilities and Wisconsin Public Power, Inc.
Minnkota – Minnkota Power Cooperative, Inc.
Minnesota Municipal – Minnesota Municipal Power Agency
Municipal Participants – Michigan Public Power Agency, Michigan South Central

Power Agency, Department of Municipal Services of Wyandotte, Michigan and City of Hamilton, Ohio
NRECA – National Rural Electric Cooperative Association
OMS – Organization of MISO States
Otter Tail – Otter Tail Power Company
PSEG – PSEG Energy Resources & Trade LLC
Reliant – Reliant Energy, Inc.
WPPI – Wisconsin Public Power Inc
WPS Resources – WPS Resources Corporation
WUMS Load-Serving Entities – Wisconsin Electric Power Company, Edison Sault Electric Company, Wisconsin Public Service Corporation, Upper Peninsula Power Company, Wisconsin Power and Light Company, Madison Gas and Electric Company, Wisconsin Public Power, Inc. and Manitowoc Public Utilities

Parties Filing Analysis Comments Pursuant to P 72 and 73 of the Procedural Order

Detroit Edison
LG&E – LG&E Energy LLC, on behalf of its utility operating companies Louisville Gas and Electric Company and Kentucky Utilities Company
Michigan/Kentucky Parties - Michigan Public Power Agency, the Michigan South Central Power Agency, the City of Wyandotte, Michigan, and the East Kentucky Power Cooperative, Inc.
Midwest ISO TOs – City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Minnesota Power (and its subsidiary Superior Water, L&P); Montana Dakota Utilities Co.; Northern States Power Company and Northern States Power Company (Wisconsin); subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest TDUs
Rural Electric Cooperatives – National Rural Electric Cooperative Association, Basin Electric Power Cooperative, Capital Electric Cooperative, Inc., Central Power Electric Cooperative, Inc., Dairyland Power Cooperative, East River Electric Power Cooperative, Inc., Hoosier Energy Rural Electric Cooperative, Inc., Great River Energy, and Minnkota Power Cooperative, Inc.

Parties Filing June 25 Comments Pursuant to P 74 of the Procedural Order

AECC - Arkansas Electric Cooperative Corporation
Cinergy – Cinergy Services, Inc., The Cincinnati Gas & Electric Company, PSI Energy,

Inc., and The Union Light, Heat and Power Company
Corn Belt – Corn Belt Power Cooperative
Detroit Edison
Dynegy – Dynegy Power Marketing, Inc. and Dynegy Midwest Generation, Inc.
FirstEnergy
Hoosier - Hoosier Energy Rural Electric Cooperative, Inc.
LG&E
Michigan/Kentucky Parties
Midwest ISO TOs – City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Minnesota Power (and its subsidiary Superior Water, L&P); Montana Dakota Utilities Co.; Northern States Power Company and Northern States Power Company (Wisconsin); subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest TDUs
Montana-Dakota – Montana-Dakota Utilities Company
North Dakota Commission – North Dakota Public Service Commission
OMS
Rural Electric Cooperatives – National Rural Electric Cooperative Association, American Public Power Association, Basin Electric Power Cooperative, Capital Electric Cooperative, Inc., Central Power Electric Cooperative, Inc., Dairyland Power Cooperative and East River Electric Power Cooperative, Inc.
TVA – Tennessee Valley Authority
WPPI
WPS Resources

<u>Parties Filing Reply Comments Pursuant to P 74 of the Procedural Order</u>

Cinergy
Michigan/Kentucky Parties
Rural Electric Cooperatives – National Rural Electric Cooperative Association, Basin Electric Power Cooperative, Capital Electric Cooperative, Inc., Central Power Electric Cooperative, Inc., Dairyland Power Cooperative, East River Electric Power Cooperative, Inc., Hoosier Energy Rural Electric Cooperative, Inc., Great River Energy, and Minnkota Power Cooperative, Inc.

Parties Filing Briefs on Exceptions

Alliant and WPS Resources
Basin, *et al.* – Basin Electric Power Cooperative, Central Power Electric Cooperative, Inc. and East River Electric Power Cooperative, Inc.
Cleveland and AMP-Ohio - The City of Cleveland, Ohio and American Municipal Power-Ohio
Dairyland
Detroit Edison
EKPC - East Kentucky Power Cooperative, Inc.
FirstEnergy
Great River – Great River Energy
LG&E
Minnesota Power
Minnkota
MMTG - Midwest Municipal Transmission Group
Montana-Dakota
Northwestern - Northwestern Wisconsin Electric Company
Otter Tail
Rural Electric Cooperatives – National Rural Electric Cooperative Association, Associated Electric Cooperative, Inc., Central Iowa Power Cooperative, Inc., Corn Belt Power Cooperative, Dairyland Power Cooperative, Minnkota Power Cooperative, Inc., and Southern Illinois Power Cooperative
Xcel – Xcel Energy Services Inc.

ATTACHMENT 2

129 FERC ¶ 61,221
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Midwest Independent Transmission System Operator, Inc.	Docket No. ER10-73-000
Midwest Independent Transmission System Operator, Inc.	Docket No. ER10-74-000
Dairyland Power Cooperative v. Midwest Independent Transmission System Operator, Inc.	Docket No. EL10-9-000

ORDER ON TARIFF REVISIONS AND COMPLAINT

(Issued December 15, 2009)

1. On October 16, 2009, pursuant to section 205 of the Federal Power Act (FPA),[1] Midwest Independent Transmission System Operator, Inc. (Midwest ISO) filed proposed revisions to section 38.8.3(A) of its Open Access Transmission, Energy, and Operating Reserve Markets Tariff (Tariff). The proposed revisions would eliminate the possibility for grandfathered agreements (GFAs) between new transmission owners and their affiliates, owner-members, and other transmission owners to be carved out of Midwest ISO's Energy and Operating Reserve Markets.[2] The proposed revisions would apply to GFAs added to Attachment P of the Midwest ISO Tariff, which lists the currently effective GFAs, on or after November 1, 2009. Separately, Midwest ISO filed revisions

[1] 16 U.S.C. § 824e (2006).

[2] The phrase "carved out" refers to a specific type of treatment of GFAs which are carved-out of Midwest ISO's energy and operating reserve markets. Carved-out GFAs are not subject to the Tariff's scheduling and settlement requirements, and are financially exempt from many energy and operating reserve market charges. The treatment of GFAs is outlined in section 38.8 of the Tariff (Tariff Sheet Nos. 656-74).

to Attachment P of its Tariff to reflect the proposed classifications for the existing GFAs of Dairyland Power Cooperative (Dairyland).

2. On October 30, 2009 Dairyland filed a complaint against Midwest ISO, requesting, essentially, that Midwest ISO's proposed tariff language governing carved-out GFA status not apply to 30 Dairyland GFAs for which Dairyland requested carved-out treatment. Dairyland asks the Commission to order the Midwest ISO to add to Attachment P each GFA that qualifies for carved-out treatment under the Tariff provisions approved and in effect as of the date of its complaint.

3. In this order, we accept in part and reject in part Midwest ISO's proposed tariff revisions to limit the eligibility for carved-out treatment going forward, reject Midwest ISO's proposal to remove existing GFAs from Attachment P, and deny the relief requested in Dairyland's complaint.

I. Background

A. GFAs

4. As part of its application to implement energy markets under its Open Access Transmission and Energy Markets Tariff (TEMT), Midwest ISO proposed tariff provisions to address transmission service provided under certain existing long-term contracts that were executed before September 16, 1998[3] (generally classified as GFAs). The Commission issued several orders addressing the treatment of GFAs under the TEMT.[4] Subsequently, the Commission accepted Midwest ISO's proposal to replace the TEMT with the Tariff,[5] which continues to include the GFA provisions that the Commission previously accepted in the GFA Orders. Midwest ISO lists the GFAs in Attachment P to the Tariff.

[3] September 16, 1998, is the date upon which the Commission granted Midwest ISO status as an independent system operator.

[4] *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 (2004), *order on reh'g*, 111 FERC ¶ 61,042, *order on reh'g*, 112 FERC ¶ 61,311 (2005) (collectively, GFA Orders), *aff'd sub nom. Wisconsin Public Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007). *See also Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,166 (2007) (allowing Midwest ISO to continue the same GFA treatment after the initial six-year transition period ended).

[5] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008).

5. Section 38.8.3(A) of the Tariff delineates the treatment of GFAs that are added to Attachment P after September 16, 2004.[6] Pursuant to this section, parties may choose to have a GFA carved out of the Energy and Operating Reserve Markets if that GFA: (1) is subject to the *Mobile-Sierra* public interest standard of review;[7] (2) is silent on the applicable standard of review; or (3) is providing for transmission service by an entity that is not a public utility. Carved-out GFAs are not subject to the Tariff scheduling and settlement requirements and are financially exempt from many energy market charges (e.g., congestion charges and loss charges).

B. Dairyland

6. Dairyland is a not-for-profit generation and transmission electric cooperative that is owned by, and provides the wholesale power requirements for, 25 separate distribution cooperatives in southern Minnesota, western Wisconsin, northern Iowa, and northern Illinois. Dairyland also provides wholesale power requirements for 16 municipal utilities in Wisconsin, Minnesota, and Iowa. Dairyland does not provide retail electric service directly to any customers, but its member cooperatives provide service to more than 251,000 retail electric customers in a 9,000 square mile area. Dairyland owns or has under contract generating units totaling approximately 1,192 MW, and owns approximately 3,144 miles of transmission lines.

7. Relevant to these proceedings, Dairyland recently announced its intent to join Midwest ISO as a transmission owner, with the goal of integrating its facilities into Midwest ISO on June 1, 2010. On September 3, 2009, Dairyland submitted a conditional application to become a transmission owner and communicated with Midwest ISO concerning the GFA status of certain contracts. Specifically, Dairyland, which is not a public utility, requested that Midwest ISO grant carved-out status to 30 of Dairyland's existing agreements, which comprise approximately 700 MW (about 79 percent of Dairyland's peak load), and add those GFAs to Attachment P of the Tariff. On October 5, 2009, Dairyland withdrew all conditions to its membership in Midwest ISO and executed the Midwest ISO Transmission Owners Agreement. On that same day, Midwest ISO communicated via letter to Dairyland that it would grant carved-out GFA status for only one of Dairyland's existing agreements.[8]

[6] September 16, 2004, is the date of the Commission order which approved Midwest ISO's approved treatment of GFAs under the TEMT.

[7] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956).

[8] Dairyland Complaint at 13-14. The agreement for which Midwest ISO stated that it would provide carved-out status is GFA No. 484, a Shared Transmission

II. Description of the Filings

A. Midwest ISO's Proposal to Limit Carved-Out GFAs – Docket No. ER10-73-000

8. On October 16, 2009, in Docket No. ER10-73-000, Midwest ISO proposed changes to its Tariff that would eliminate, going forward, the availability of the carved-out GFA option for new transmission owners whose GFA is with an affiliate, owner-member company, and/or other transmission owner. Under the Midwest ISO proposal, carved-out GFA treatment will not be available for such GFAs added to Attachment P on or after November 1, 2009.[9] Instead, pursuant to the proposed tariff language, the agreements must be fully converted to service under the Tariff. (As addressed later, while the proposed tariff language states that conversion to service under the Tariff is required, Midwest ISO's transmittal letter contains contradictory statements that Options A and C will also be available.) Specifically, Midwest ISO proposes to add the following language to section 38.8.3(A) of the Tariff:

> Notwithstanding the foregoing, carved-out treatment under this paragraph b shall not be available to Grandfathered Agreements added to Attachment P of the Tariff effective on or after November 1, 2009, that involve service to an Affiliate or an owner-member of the Transmission Owner or to an entity that itself is a Transmission Owner. Any such agreements between Transmission Owners shall be fully converted to service under the Tariff for the internal loads of the affected Transmission Owners.

9. Midwest ISO states that the proposed revisions are consistent with the Commission's guidance with respect to carved-out GFAs, and consistent with the Commission's expectation that the amount of load served under carved-out GFAs, and the resulting cost shift to Tariff customers, would decline over time.[10] Midwest ISO

Agreement between Dairyland and Western Wisconsin Municipal Power Group, dated April 8, 1985.

[9] While the revised tariff language would exclude carved-out treatment only for GFAs between the new transmission owner and another transmission owner which are added to Attachment P on or after November 1, 2009, Midwest ISO's action in de-listing certain of Dairyland's existing GFAs in its proposal in Docket No. ER10-74-000 indicates that it intends its proposal to apply to such GFAs between the new transmission owner and other transmission owners that were added to Attachment P prior to November 1, 2009, as well.

[10] *See* Midwest ISO GFA Amendment Filing at 5-6.

argues that allowing new transmission owners to obtain carved-out status for a large percentage of GFAs places an unfair burden on existing members to subsidize the congestion costs of utilities that have voluntarily elected to avail themselves of the benefit of Midwest ISO's markets. According to Midwest ISO, by negotiating with prospective members to ensure that carved-out load remains small and manageable, Midwest ISO has been able to meet that expectation. Midwest ISO argues, however, that Dairyland's membership application tests its ability to preserve this balance, and notes that Dairyland has requested carved-out GFA status for over 70 percent of its load, including contracts with its retail cooperative members. Midwest ISO contends that it has received expressions of membership interest from other prospective transmission owners that may have GFA profiles similar to Dairyland. Midwest ISO argues that its proposed Tariff changes are necessary because the Tariff is not explicit on Midwest ISO's ability to limit the addition of carved-out GFAs.

10. Midwest ISO requests waiver of the 60-day prior notice requirement to permit an effective date of October 17, 2009, one day after filing, for its proposed tariff revisions.

B. <u>Classification of Dairyland's GFAs – Docket No. ER10-74-000</u>

11. On the same day Midwest ISO filed the proposed Tariff changes, it also filed, in Docket No. ER10-74-000, amendments to Attachment P to reflect its proposed classifications of Dairyland's agreements, effective June 1, 2010. Midwest ISO proposes adding one Dairyland agreement to Attachment P as a carved-out GFA and deleting five Dairyland GFAs that were previously listed on Attachment P.[11] Because Midwest ISO is proposing that its new GFA provisions take effect prior to Dairyland's integration into Midwest ISO on June 1, 2010, Midwest ISO contends that it determined which of Dairyland's existing agreements qualify for GFA status by using its proposed new standards.

12. According to Midwest ISO, the percentage of proposed carved-out GFAs, which comprise 80 MW (approximately 9 percent of Dairyland's total load), is consistent with

[11] Specifically, Midwest ISO proposes to add GFA No. 484, a Shared Transmission Agreement between Dairyland and Western Wisconsin Municipal Power Group dated April 8, 1985, and to remove GFA Nos. 20 and 41 (an August 19, 1966 Interconnection and Interchange Agreement and a November 15, 1978 General Transmission Facilities Installation Agreement with Interstate Power Company); GFA No. 290 (a May 30, 1985 Phase Angle Regulating Transformer Cost Sharing Agreement with Minnesota Power Inc.); 293 (a September 16, 1983 Interconnection and Facility Use Agreement with Northwestern Wisconsin Electric Company (Northwestern Wisconsin)); and GFA No. 467 (a June 16, 1982 Shared Transmission Agreement with Southern Minnesota Municipal Power Agency (SMMPA)).

the Commission's previous GFA orders in which the Commission allowed carve-outs only to the extent they constitute a small and gradually diminishing portion of Midwest ISO's total load.[12]

C. <u>Dairyland's Complaint – Docket No. EL10-9-000</u>

13. In response to Midwest ISO's proposed tariff changes limiting the availability of carved-out status for new transmission owners, and its proposed amendment to Attachment P, Dairyland filed a complaint in Docket No. EL10-9-000. Dairyland argues that it should be subject to the Tariff as it existed when Dairyland made its commitment to join Midwest ISO, and that it should therefore receive carved-out GFA status for all 30 of its GFAs that meet the requirements of the currently-approved Tariff. Dairyland asserts that, throughout integration discussions with Midwest ISO, it understood that its GFAs would be fully subject to the terms of the Tariff on file at the time of the discussions, in accordance with the filed rate doctrine. Dairyland further argues that there is no support for Midwest ISO's assertion that an increase in carved-out load would impair reliable operation of the Midwest ISO system. Accordingly, Dairyland requests that the Commission require Midwest ISO to include in Attachment P, effective October 31, 2009, the GFAs that Midwest ISO has proposed to delete (namely, GFA Nos. 20, 41, 290, 293 and 467), along with 25 Member All-Requirements Contracts under which Dairyland sells and delivers energy to member entities.

14. Dairyland alleges that once a potential transmission owner has committed to integrating its facilities into Midwest ISO, Midwest ISO makes certain filings on behalf of that new owner that ensures that the transmission owner can complete its integration in a timely way. Dairyland contends that, pursuant to Commission orders, parties who wish to modify GFA information should submit the requisite requests to Midwest ISO, which will then file the changes with the Commission. Dairyland states that the version of Attachment P that Midwest ISO filed in Docket No. ER10-74-000 was unilaterally proposed by Midwest ISO, and that the filing violated Midwest ISO's tariff obligation to include Dairyland's GFAs. Dairyland describes the 30 GFAs that it seeks to include in Attachment P, and provides arguments that each qualify for carved-out status.

15. Next, Dairyland argues that while Midwest ISO's communications with Dairyland offer policy reasons for denying Dairyland carved-out GFA status, implementing such policy choices requires changing the Tariff. Dairyland contends that its complaint addresses the issue of whether its GFAs meet the filed tariff requirements for carved-out GFAs and, accordingly, should be included in Attachment P. It further argues that the

[12] Midwest ISO Attachment P Filing at 3-4 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236, at P 143 (2004) ("September 16, 2004 Order"), *order on reh'g*, 111 FERC ¶ 61,042 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,166, at P 70, 45, 48 (2007)).

question of whether Midwest ISO complied with its tariff should be judged based on the tariff that existed when Dairyland submitted its GFAs, not a new tariff proposal that Midwest ISO seeks to implement through prospective tariff changes.

16. Finally, Dairyland contends that Midwest ISO told it that a GFA that was previously carved out because a counterparty was not a Midwest ISO transmission owner could no longer be carved out once the counterparty became a transmission owner. Dairyland points out that the new Tariff language does not prohibit carved-out GFAs involving two Midwest ISO transmission owners; nor does the definition of a GFA mention any exception where both entities are transmission owners. Dairyland provides specific examples of GFAs presently listed on Attachment P that are between two transmission owners. Furthermore, Dairyland claims that its Member All-Requirements Contracts qualify as GFAs even though they were extended after September 16, 1998, i.e., the cut-off date for receiving grandfathered status. Dairyland maintains that the Tariff's definition of GFA does not state that an extension of the term of the GFA renders it ineligible for GFA treatment; nor has Midwest ISO previously pointed to any case law to support such an assertion.

17. Finally, Dairyland moves to consolidate its complaint with Midwest ISO's rate filings in Docket Nos. ER10-73-000 and ER10-74-000. It argues that consolidation will further administrative efficiency, and because common issues of law and fact are involved.

III. Notice of Filings and Responsive Pleadings

A. Midwest ISO's Proposal to Limit Carved-Out GFAs – Docket No. ER10-73-000

18. Notice of Midwest ISO's filing in Docket No. ER10-73-000 was published in the *Federal Register*, 74 FR 54984 (2009), with interventions and protests due on or before November 6, 2009.

19. Timely motions to intervene were filed by American Municipal Power, Inc. (AMP); Consumers Energy Company (Consumers); Duke Energy Corporation (Duke Energy); Exelon Corporation; ITC Holdings Corp. (ITC); Jo-Carroll Energy, Inc. (Jo-Carroll); Northwestern Wisconsin; SMMPA; Western Area Power Administration (WAPA); and Wisconsin Electric Power Company (Wisconsin Electric). The National Rural Electric Cooperative Association (NRECA) filed a motion to intervene out-of-time.

20. Timely motions to intervene and comments were filed by Great River Energy (Great River); Hoosier Energy Rural Electric Cooperative, Inc. and Southern Illinois Power Cooperative (collectively, Hoosier and Southern Illinois); and the Midwest ISO

Transmission Owners (Midwest ISO TOs).[13] Timely motions to intervene and protests were filed by Central Iowa Power Cooperative; Corn Belt Power Cooperative; Dairyland; EPIC Merchant Energy Midwest L.P., SESCO Enterprises LLC, Jump Power, LLC, and Big Bog Energy LP (collectively, Financial Marketers); and Minnkota Power Cooperative, Inc. (Minnkota). A timely joint motion to intervene and protest was filed by Basin Electric Power Cooperative (Basin Electric) and Associated Electric Cooperative, Inc. (Associated Electric). Answers were filed by Midwest ISO, MidAmerican, and Basin Electric.

B. Classification of Dairyland's GFAs – Docket No. ER10-74-000

21. Notice of Midwest ISO's filing in Docket No. ER10-74-000 was published in the *Federal Register*, 74 FR 56603 (2009), with interventions and protests due on or before November 6, 2009.

22. Timely motions to intervene were filed by AMP; American Transmission Company, LLC; Associated Electric; Basin Electric; Consumers; Duke Energy; Great River; ITC; Jo-Carroll; Midwest ISO TOs; Michigan Public Power Agency; Michigan South Central Power Agency; Northwestern Wisconsin; SMMPA; WAPA; Western Wisconsin Municipal Power Group; and Wisconsin Electric. NRECA filed a motion to intervene out-of-time. A timely motion to intervene and comments were filed by Hoosier and Southern Illinois. Timely motions to intervene and protest were filed by Dairyland and Financial Marketers. Answers were filed by Midwest ISO and MidAmerican.

C. Dairyland's Complaint – Docket No. EL10-9-000

23. Notice of Dairyland's complaint was published in the *Federal Register*, 74 FR 57668-69 (2009), with interventions and protests due on or before November 19, 2009.

24. Timely motions to intervene were filed by AMP; Consumers; Duke Energy; ITC; Jo-Carroll; Midwest ISO TOs; Northwestern Wisconsin; and SMMPA. A timely motion

[13] For the purpose of these filings, the Midwest ISO Transmission Owners include: American Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp.; City of Columbia Water and Light Department (Columbia, Missouri); City Water, Light & Power (Springfield, Illinois); Indiana Municipal Power Agency; Indianapolis Power & Light Company; MidAmerican Energy Company (MidAmerican); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Otter Tail Power Company; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

to intervene and comments were filed by Hoosier and Southern Illinois. Timely motions to intervene and protest were filed by Great River, and Financial Marketers. Answers were filed by Midwest ISO and Dairyland.

IV. Discussion

A. Procedural Matters

25. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2009), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. We will grant NRECA's unopposed, late-filed motions to intervene in Docket Nos. EL10-73-000 and EL10-74-000, given its interests in these proceedings, the early stage of the proceedings, and the lack of undue prejudice or delay.

26. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2009), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers filed herein because they have provided information that assisted us in our decision-making process.

27. We will deny Dairyland's motion to formally consolidate these three proceedings. We need not take this step in order to consider the common issues of fact and law at the same time.

B. Substantive Matters

1. Comments and Protests Regarding Tariff Revisions

28. In response to Midwest ISO's proposed tariff changes limiting the availability of carved-out status for new transmission owners, and its proposed amendment to Attachment P, Dairyland argues that there is no support for Midwest ISO's contention that an increase in carved-out load would impair reliable operation of the Midwest ISO system or unfairly shift costs to other Midwest ISO members. It also states that the proposal to remove the carved-out GFA option constitutes a request to modify terms and conditions of the GFAs, and that GFAs, as protected under *Mobile-Sierra*, can only be modified if required by the public interest. Further, Dairyland argues that Midwest ISO itself proposed to continue the carved-out GFA option after the transition period. It notes that Midwest ISO's quarterly GFA reports continue to cite efficient commitment and dispatch of generation and a generally high level of day-ahead scheduling accuracy.

29. Dairyland requests that the Commission reject Midwest ISO's proposed amendment as unjust and unreasonable, or, in the alternative, deny waiver of the notice requirement and set the proposed amendment for hearing. In support of its position, Dairyland argues that the Commission ordered Midwest ISO to carve out GFAs where

the transmission provider is a non-jurisdictional entity or where the contract is silent on the standard of review. Dairyland further contends that the currently-approved Tariff provides for such treatment. According to Dairyland, Midwest ISO recently stated that GFAs should continue to be carved out.[14] Dairyland states that none of the quarterly reports indicated problems that suggested that carved-out treatment needs to be restricted; in fact, in the most recent quarterly report filed on October 30, 2009, Midwest ISO reported "continued overall improvement and a general high level of day-ahead scheduling accuracy relating to Carved-Out GFAs in the Midwest ISO's Region."[15]

30. Dairyland contends that the proposed tariff amendment is unduly discriminatory and treats similarly situated parties differently based on an arbitrary date. In addition, Dairyland argues that the United States Court of Appeals for the District of Columbia Circuit has found that not granting carved-out status to non-jurisdictional GFAs abrogates them, which the Commission does not have authority to do.[16] Dairyland further argues that, in not adhering to its filed tariff and in not amending Attachment P to include Dairyland's GFAs, Midwest ISO violated the filed rate doctrine. Finally, Dairyland argues that Midwest ISO's proposed Tariff amendment provides no basis for its proposal to delete four GFAs from the current Attachment P.

31. Numerous additional protests and comments were filed in Docket No. ER10-73-000, mostly by non-member cooperatives, raising arguments similar to Dairyland's. Financial Marketers argue that none of Dairyland's GFAs should be classified as carved-out because carving out such GFAs would result in Revenue Sufficiency Guarantee costs attributable to those GFAs being shifted to financial marketers and other participants conducting virtual transactions in the Midwest ISO markets.

2. <u>Answers to Protests</u>

32. In its answer to Dairyland's protest in Docket No. ER10-73-000, Midwest ISO argues that *Mobile-Sierra* is not implicated because no contract will be unilaterally abrogated or modified by the proposed amendment; rather, the amendment applies to new transmission owners and involves two prospective exceptions to the continued availability of the carved-out GFA option. In response to arguments that its proposed amendment is discriminatory or inconsistent with previous GFA orders, Midwest ISO

[14] Dairyland Protest in Docket No. ER10-73-000 at 10.

[15] October 2009 Quarterly GFA Report at 4.

[16] Dairyland Protest at 31-32, Docket No. EL10-73-000 (citing *Wisconsin Public Power, Inc. v. FERC*, 493 F.3d 239, 273 (D.C. Cir. 2007)).

contends that Dairyland, as a new member to Midwest ISO, is not subject to any forced transition and is free to decide whether to subject itself to Midwest ISO's market rules.

33. Midwest ISO further argues that carved-out GFAs were a temporary and limited exception to non-discriminatory treatment, and were possible due to the small number of megawatts involved. Midwest ISO adds that the number of GFAs receiving carved-out status was expected to shrink over time. According to Midwest ISO, carve-outs have a negative impact on efficiency and reliability, and cause cost shifts. Midwest ISO further notes that most of the parties protesting the proposed change are not transmission owners, adding that these parties would not be harmed by the proposed amendment to Tariff section 38.8.3(A).

34. Basin Electric and Associated Electric urge the Commission to reject Midwest's ISO's assertion that its proposal would not implicate the *Mobile-Sierra* doctrine because contracts will be unilaterally modified by the proposed revisions.

35. MidAmerican states that some parties noted that Midwest ISO accepted a number of carved-out GFAs in conjunction with MidAmerican's recent integration as a transmission-owning member. MidAmerican clarifies, in its answer, that Midwest ISO performed a significant review of all of MidAmerican's GFAs, and any carved-out GFA service that MidAmerican was using to supply load within the Midwest ISO market was, at Midwest ISO's direction, converted to standard service under the Tariff; thus, the GFA treatment afforded MidAmerican is identical to the treatment it would have received if the proposed tariff changes were in place at the time of MidAmerican's integration. MidAmerican believes such treatment is just and reasonable.

3. Midwest ISO's Answer to Dairyland's Complaint

36. In its answer to Dairyland's complaint in Docket No. EL10-9-000, Midwest ISO contends that it acted appropriately in limiting the size of Dairyland's carve-outs based on representations Dairyland made, prior to signing the Transmission Owners Agreement, that it intended to grandfather only a small percentage of its load involving "third party" agreements with municipal or non-Dairyland utilities. Midwest ISO contends that, in connection with its application for membership, Dairyland withdrew and waived any condition pertaining to the full invocation of its eligibility for carved-out treatment. In addition, Midwest ISO argues that Dairyland's agreements with its owner-members lost their eligibility for grandfathered status when they were amended in 2004 to extend their terms. Midwest ISO avers that the most reasonable interpretation of the Tariff's definition of GFAs is that its identification of September 16, 1998, as a cut-off date for grandfathering status precludes the further grandfathering of GFAs through amendments that extend fixed termination dates. Midwest ISO cites a Commission order finding that the amendment of a preexisting transmission agreement has the effect of

subjecting that agreement to the Tariff.[17] Midwest ISO further contends that Dairyland's arguments about the filed rate doctrine are unavailing because, by the time Dairyland fully integrates, the filed rate would include the carve-out limitations (if accepted by the Commission).

4. Dairyland's Answer

37. In its answer, Dairyland argues that, contrary to Midwest ISO's assertion that Dairyland "did not regard the narrowing of the scope of the GFA carve-outs as a deal-breaker with respect to integration into the Midwest ISO," Dairyland never waived a legal right to challenge Midwest ISO's decision with respect to its eligibility for carved-out GFA treatment under the Tariff.[18] Dairyland further contends that Midwest ISO's answer does not sufficiently rebut the position that new transmission owners should be provided the same protection as existing transmission owners, and adds that if carved-out GFA status would not impair any utility's ability to do business, or would not impose an excessive burden on other utilities, then new transmission owners should not be denied carved-out status for GFAs that would otherwise qualify for such treatment under the Tariff.

38. Dairyland argues that its all-requirements contracts merit carved-out status, regardless of whether those contracts were amended after September 16, 1998. Dairyland contends that amendments to GFAs do not imperil their status as carved-out GFAs. According to Dairyland, the Commission has, in the past, permitted pre-Order No. 888 transmission service agreements to be amended without requiring conversion to service under an open-access transmission tariff.[19]

5. Commission Determination

a. Proposal to Limit Carved-Out GFA Option – ER10-73-000

39. We accept, subject to modification, the portion of Midwest ISO's proposed revisions to Tariff section 38.8.3(A) that eliminates the availability of carved-out GFA status for existing agreements between a new transmission owner and its affiliates and/or owner-members. We note that this change will be prospective in nature, and that it does not implicate the Commission's prior findings regarding GFAs. Those findings were premised on the fact that the start-up of Midwest ISO's energy markets would affect the GFAs of *existing* transmission owner members of Midwest ISO – for example, by imposing scheduling and settlement requirements to which GFAs had never been subject.

[17] *See* Midwest ISO November 19, 2009 Answer at 11 (citing *Interstate Power Co.*, 112 FERC ¶ 61,048, at P 4 (2005)).

[18] *See* Dairyland Dec. 4, 2009 Answer at 4-5.

[19] *See id.* at 11-13.

40. By contrast, Dairyland is a *prospective* transmission owner. Unlike the transmission-owning members who were already part of Midwest ISO at the time of energy market start-up, Dairyland can analyze the costs of converting its GFAs to tariff service prior to integration, and weigh those costs against the benefits of Midwest ISO membership. We further note that the GFAs at issue are, in essence, contracts between the prospective member and itself, which the prospective member can modify to avoid any trapped costs that might otherwise result. In particular, if a transmission owner must pay costs associated with the energy market to fulfill its obligations under a GFA, but the GFA does not provide for a pass-through of those costs, the transmission owner cannot recover its costs and those costs will become essentially "trapped." The decision to modify any of its existing contracts is entirely at the discretion of the prospective member; the Commission is not directing or coercing any potential Midwest ISO member to modify its existing contracts.[20] We therefore disagree with Dairyland that the *Mobile-Sierra* doctrine requires that its contracts be carved out, and that Midwest ISO's change to the tariff provisions governing GFA treatment amounts to undue discrimination based on an arbitrary date.

41. We find that our acceptance of Midwest ISO's proposed tariff language is also consistent with prior Commission findings regarding GFAs. When the carved-out GFA option was originally accepted, and when the Commission allowed it to continue after the transition period, the Commission envisioned that the amount of load attributable to these GFAs would decrease over time.[21] Up until now, that has been the case. However, if Dairyland is permitted to elect carved-out status for all of its existing contracts with its owner-members, this will reverse the trend. As noted above, Dairyland's proposed additions to the carve-out total approximately 700 MW – more than 10 percent of the 6,786 MW currently carved out of the Midwest ISO markets.[22]

42. Although we accept Midwest ISO's proposal to limit availability of carved-out treatment for agreements between the new transmission owner and an affiliate or owner-member, that are not already included in Attachment P, we reject Midwest ISO's proposal to eliminate the availability of carve-out GFA status for existing agreements

[20] In contrast, in the GFA proceedings, the Commission had to decide whether to abrogate the *existing* GFAs of existing transmission-owning members to accommodate the start-up of Midwest ISO's energy markets.

[21] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,166, at P 70 (2007).

[22] The amount of carved-out GFAs is based on the GFA listing in Midwest ISO's October 30, 2009 informational filing in Docket Nos. ER04-691-000, ER04-106-000, EL04-104-000, and ER07-532-000.

between a prospective new member and another transmission owner. Unlike existing agreements between a prospective member and its affiliates or owner-members, which are not currently listed in Attachment P, many existing agreements between prospective members and existing transmission owners are already listed in Attachment P. (For instance, in the case of Dairyland, Midwest ISO is proposing to delete five GFAs that are currently listed in Attachment P.) In addition, Midwest ISO's proposed tariff language, as written, would not allow it to make such deletions. The proposed language would apply to GFAs between transmission owners "added to Attachment P of the Tariff effective on or after November 1, 2009," but it does not address agreements between transmission owners that are already listed in Attachment P.

43. We also note that Midwest ISO specifically states in its transmittal letter that GFA Options A and C, and full Tariff conversion, will continue to be available to GFAs that were otherwise previously eligible for carved-out treatment,[23] but its proposed tariff language does not include this option.[24] As such, we direct Midwest ISO to revise its proposed tariff sheets within 30 days of the date of this order to make Option A and Option C GFA treatment available for existing agreements with affiliates and member-owners.

44. In addition, the prospective member cannot unilaterally modify existing agreements with transmission owners. In that respect, those agreements are similar to agreements between the prospective member and unaffiliated non-members, which would still qualify for carved-out treatment under Midwest ISO's proposal. A transmission owner could, for example, refuse to allow modification of a GFA that is already listed in Attachment P. In that case, if the prospective member still wanted to join Midwest ISO, it would face the possibility of trapped costs, since it would have to cover any additional costs associated with converting the GFA to service under the Tariff while still having to provide service under the terms of the GFA. Midwest ISO has not addressed the trapped cost issue, or explained why it is appropriate to treat contracts between the prospective

[23] *See* Midwest ISO GFA Amendment Filing at 4.

[24] Under Option A, the GFA Responsible Entity – a designated contract party financially responsible for energy market activities associated with the GFA – nominates and holds financial transmission rights in order to transact under the GFA. Midwest ISO assesses congestion charges and the cost of losses for all transactions under the GFA. Under Option C, the GFA Responsible Entity does not nominate or hold financial transmission rights for the GFA transactions but must pay the costs of congestion for all GFA transactions. Pursuant to section 38.8.3 of the currently effective Tariff, these options are made available to market participant applicants that are party to GFAs and intend to maintain service under such GFAs.

member and a transmission owner differently than contracts between the prospective member and unaffiliated non-members. Therefore, we reject this provision, without prejudice to Midwest ISO re-filing it with appropriate explanation and/or changes. Midwest ISO is directed to file, within 30 days of the date of this order, revised tariff language reflecting the removal of language that precludes the carved-out option for GFAs between a prospective new transmission owning member of Midwest ISO and any other transmission owner.

45. Although we accept in part the revised tariff language in section 38.8.3(A), we deny Midwest ISO's request for waiver of the 60-day prior notice requirement for failure to demonstrate good cause, and make these tariff changes effective December 16, 2009.[25]

b. Proposal To Classify Dairyland's GFAs – ER10-74-000

46. Regarding Midwest ISO's proposed classification of Dairyland's GFAs, we acknowledge that there appears to have been some miscommunication between Midwest ISO and Dairyland regarding the GFAs that would receive carved-out status. Dairyland claims that Midwest ISO knew that Dairyland intended to carve out its member-owner load, but Midwest ISO states that Dairyland instead indicated that it intended to request carve-out status only for a small number of existing agreements with third parties.

47. Despite the misunderstanding, we find that the new tariff changes accepted herein should apply to Dairyland's GFAs upon integration into Midwest ISO. Although Dairyland states that it relied on the Tariff language in effect when it unconditionally agreed to join Midwest ISO on October 5, 2009, Dairyland admits that a Midwest ISO staff member told Dairyland on September 29, 2009, that Midwest ISO did not intend to grant carved-out status to Dairyland's existing member-owner agreements. Dairyland could have waited to sign the Transmission Owners Agreement until the GFA issue was resolved, but it did not. In addition, in a letter to Midwest ISO dated October 13, 2009, Dairyland acknowledged that there was an ongoing dispute regarding the carved-out status of certain existing agreements, but stated that it was waiving any conditions to Dairyland's membership application and, as a signatory to the Transmission Owners Agreement, indicated that is had no conditions precedent to becoming a transmission owning member. Furthermore, in the October 13, 2009 letter, Dairyland also stated that it "looks forward to approval of Dairyland's application by the Midwest ISO Board at its October 15, 2009 meeting." In response to that request, the Midwest ISO Board approved Dairyland's unconditional membership application at its October 15, 2009 meeting.

[25] This action is consistent with *Central Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, *reh'g denied,* 61 FERC ¶ 61,089 (1992) because Midwest ISO has not demonstrated good cause to waive the 60-day prior notice requirement.

48. Dairyland's membership in Midwest ISO will not take effect until June 1, 2010 and Midwest ISO's proposed changes will become effective on December 16, 2009. The proposed tariff provision would therefore apply to all GFAs that have not been accepted by the Commission for inclusion in Attachment P as carved-out agreements by that date. Dairyland admits that the listing in Attachment P of any of its GFAs that are not already included there would take effect June 1, 2010. Therefore, the new tariff provisions in effect on December 16, 2009 would apply to Dairyland's GFAs.

49. While the timing of the Midwest ISO's filings and Dairyland's signing the Transmission Owner Agreements is awkward, we note that Midwest ISO is not precluded from proposing such changes to its Tariff simply because Dairyland will become a member at some point in the future. For example, there is no provision in the Transmission Owners Agreement that specifically addresses the availability of carved-out status for GFAs or otherwise provides assurance that Tariff provisions will not change between the date a new member signs the Transmission Owners Agreement and the date such membership takes effect. Also, as noted above, applying the tariff changes to Dairyland's existing agreements does not implicate prior Commission findings. Questions about standard of review for the GFAs do not apply here, since the Commission is not requiring or coercing any changes and the new member has the ability to amend the agreements that are affected because they are with affiliates. As noted above, Dairyland was aware of Midwest ISO's position regarding treatment of its GFAs before it made its final decision to join Midwest ISO. That decision to join Midwest ISO was entirely voluntary, and if it chose not to join, it would not have to change any contracts. Nor does Dairyland argue that it cannot modify its contracts with its members to pass through costs it incurs for settlements in the Midwest ISO markets. In addition, as explained above, we reject Midwest ISO's proposal to not allow carved-out status for agreements between a prospective member and existing transmission owners listed on Attachment P, as well as Midwest ISO's proposal to delete certain GFAs already listed in Attachment P. Therefore, GFAs that the Commission already addressed in prior proceedings will not be affected.

50. We also find Midwest ISO's proposal to make carved-out treatment unavailable for existing service to an owner-member of a transmission owner is appropriate because it is similar to how bundled retail load is treated under the Midwest ISO Tariff. The sales that a generation and transmission cooperative such as Dairyland makes to its owner-members are wholesale sales, but the purpose of those wholesale sales (and, in fact, the purpose of the generation and transmission cooperative itself) is to provide for the owner-member's sales to its bundled retail load. Unlike a full requirements sale to an unaffiliated third party, where the third party would have no say in whether Dairyland joined Midwest ISO, the wholesale requirements sales Dairyland seeks to carve-out are to member-owners without whose approval Dairyland would not be able to join the Midwest ISO.

51. Because of this similarity, the proper comparison for how existing sales to owner-members are treated once Dairyland joins Midwest ISO is not to how Midwest ISO treats existing sales between a transmission owner and an unaffiliated third-party, but rather how Midwest ISO treats bundled retail sales. A transmission owner that serves bundled retail load must take service under the Midwest ISO Tariff to serve that load,[26] which is *not* carved-out of the energy market. The service a transmission owner takes to serve bundled retail load is subject to all the energy market rules and charges.[27] Indeed, MidAmerican, the most recent new member of Midwest ISO, notes in its answer that it is taking service under the Midwest ISO Tariff (i.e., it does not receive carved-out treatment) for its entire bundled retail load located within the Midwest ISO footprint.

c. <u>Complaint – EL10-9-000</u>

52. Based on our determination that Dairyland's GFAs would be subject to the new tariff language proposed by Midwest ISO in Docket No. ER10-73-000, we deny the relief requested in Dairyland's complaint. Dairyland does not persuade us that Midwest ISO's alleged failure to file the Attachment P tariff sheets that Dairyland provided it is actually a tariff violation. The complaint does not indicate which section of the tariff requires such a filing, and we observe that Midwest ISO was not, in any case, required to file a tariff amendment until 60 days prior to Dairyland's planned integration into Midwest

[26] Midwest ISO must be the sole provider of transmission service over its system and, therefore, transmission owners must take service under the Midwest ISO Tariff to serve their bundled retail load. The terms and conditions of the underlying agreements for service to bundled retail customers are not modified, but the transmission owner takes service under the Tariff for the service that it in-turn uses to service its bundled retail load. *See Midwest Indep. Transmission Sys. Operator, Inc.*, Opinion No. 453, 97 FERC ¶ 61,033, at 61,170-71 (2001), *order on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002), *order on remand*, 102 FERC ¶ 61,192 (2003), *reh'g denied*, 104 FERC ¶ 61,012 (2003), *aff'd sub nom. Midwest ISO Transmission Owners, et al.* v. *FERC*, 373 F.3d 1361 (D.C. Cir. 2004). The terms and conditions of the underlying agreements for service to bundled retail customers are not modified, but the transmission owner takes service under the Tariff for the service that it in-turn uses to service its bundled retail load.

[27] Although transmission service for bundled retail load is fully within the energy markets, the service is treated similarly to service under an Option A GFA in that it is not subject to transmission service charges under Schedule 9 (Network Integration Transmission Service) of the Midwest ISO Tariff. As discussed earlier, we are requiring Midwest ISO to offer Option A for GFAs that cover service to a generation and transmission cooperative's owner-members.

ISO.[28] We do not find error in Midwest ISO's decision to file the Attachment P it hoped to make effective at the time of Dairyland's integration. We note, however, that Midwest ISO is required to reinstate those GFAs which were previously included in Attachment P, but which Midwest ISO proposed to remove in these proceedings.

The Commission orders:

(A) Midwest ISO's filling in Docket No. ER10-73-000 is hereby accepted in part and rejected in part, effective December 16, 2009, subject to Midwest ISO making a compliance filing within 30 days of the date of this order to correct inconsistencies with the filed tariff language, as discussed in the body of this order.

(B) Midwest ISO's filing in Docket No. ER10-74-000 is hereby rejected. Midwest ISO is ordered to submit revised tariff sheets under Attachment P reflecting the reinstatement of the GFAs that were previously listed on Attachment P prior to November 1, 2009, to be effective June 1, 2010.

(C) The relief requested in Dairyland's complaint is hereby denied as it relates to applying the currently effective tariff language in determining carved-out GFA status. Dairyland's thirty GFA contracts will be classified as described in this order.

(D) Dairyland's motion to consolidate the instant proceedings is hereby denied.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[28] *See* 18 C.F.R. § 35.3(a)(1) (2009).

ATTACHMENT 3

1.276 Grandfathered Agreement(s) (GFA): An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

1.277 Grandfathered Agreement (GFA) Responsible Entity: An entity financially responsible for all costs incurred by transactions pursuant to Grandfathered Agreement(s) under this Tariff.

1.278 Grandfathered Agreement (GFA) Schedule: A Schedule associated with a Grandfathered Agreement.

38.8.3 Optional Treatment of Transactions Pursuant to Grandfathered Agreements

Market Participant Applicants that are party to Grandfathered Agreement(s) and intend to maintain service under such agreements shall select one of three options for scheduling and settlement of Costs of Congestion and Costs of Losses resulting in the Day-Ahead Energy and Operating Reserve Market and shall so notify the Transmission Provider in writing:

a. **Option A.**

i. Treatment of ARRs and FTRs: The GFA Responsible Entity shall be entitled to nominate the Capacity under the Grandfathered Agreement(s) for allocation of ARRs pursuant to the procedures set forth in Section 43.1.2. The GFA Responsible Entity shall be allocated ARRs, shall hold the ARRs and shall be responsible for all credits, debits, rights, and responsibilities associated with the ARR(s) as set forth in Section 42. The GFA Responsible Entity may self-schedule the ARRs in the annual FTR Auction to convert the ARRs to FTRs

ii. Treatment of Transmission Congestion: The Transmission Provider shall charge the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to Dispatch Instruction or Day-Ahead Schedules based on the designated Internal Delivery Points or GFA Schedule Receipt Points and GFA Schedule Delivery Points for the Grandfathered Agreement(s), as set forth in Section 39.3.3 and 40.4.

iii. Treatment of Transmission Losses: The GFA Responsible Entity shall be assessed the Cost of Losses for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Points or GFA Schedule Receipt Point and GFA Schedule Delivery Point, as set forth in Section 39.3.3 and 40.4.

c. **Option B.**

i. Treatment of ARRs and FTRs. The GFA Responsible Entity will not nominate or receive ARRs nor be eligible for conversion of FTRs in the annual FTR Auction for the Capacity under the GFA, but will instead receive a refund of the Cost of Congestion resulting from the Day-Ahead Schedules cleared in the Day-Ahead Energy and Operating Reserve Market. The GFA Responsible Entity shall be responsible for the Transmission Provider's administrative costs associated with accounting for the ARRs and FTRs under this option as set forth in Schedule 16 of this Tariff.

ii. Treatment of Transmission Congestion. The Transmission Provider shall charge the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Point or the GFA Schedule Receipt Point and the GFA Schedule Delivery Point under the Grandfathered Agreement(s) but shall credit back the full amount of the Cost of Congestion resulting from Day-Ahead Schedules cleared in the Day-Ahead Energy and Operating Reserve Market to the GFA Responsible Entity. This refund will only be provided if the GFA Scheduling Entity submits a

GFA Schedule according to the procedures specified in Section 39.1.4 for the Day-Ahead Energy and Operating Reserve Market for the Grandfathered Agreement transaction(s) prior to the closing of the Day-Ahead Energy and Operating Reserve Market, consistent with the Internal Delivery Point or, the GFA Schedule Receipt Point and the GFA Schedule Delivery Point, and within the maximum MW Capacity permissible under the Grandfathered Agreement. In the event that there results a revenue inadequacy, the Transmission Provider shall fully compensate the GFA Responsible Entity for the Costs of Congestion. The revenue inadequacy shall be funded through an assessment of debits on all Market Participants on a *pro-rata* basis, based on their Market Load Ratio Share. The Transmission Provider shall account for Grandfathered Agreements under Option B in the Annual ARR Allocation and annual FTR Auction processes, but shall not actually allocate ARRs or assign FTRs to the GFA Responsible Entity. The Transmission Provider shall not provide a preference to ARRs or FTRs associated with Option B Grandfathered Agreements held by the Transmission Provider.

iii. Treatment of Transmission Losses. The Transmission Provider shall charge the GFA Responsible Entity the Cost of Losses for all transactions under the Grandfathered Agreement based on the designated Internal Delivery Point or GFA Schedule Receipt Point and GFA Schedule Delivery Point, as set forth in Section 39.3.3 and 40.4. The Transmission

Provider shall credit back to the GFA Responsible Entity the difference between Marginal Losses and System Losses at the designated Internal Delivery Points or GFA Schedule Receipt Point and GFA Schedule Delivery Point. The difference between Marginal Losses and System Losses shall be determined by dividing the amount of Marginal Losses for a transaction by two (2), consistent with the procedures described in the Business Practices Manuals. This refund will only be provided if the GFA Scheduling Entity submits a transaction for the Grandfathered Agreement transaction(s) the day prior to the Operating Day, consistent with the source and sink point and within the maximum MW Capacity permissible under the Grandfathered Agreement. GFA Responsible Entities that receive such reimbursement for GFA transactions shall not receive an allocation of the Local Balancing Authority Marginal Losses Surplus Share.

c. **Option C.**

i. Treatment of ARRs and FTRs. The GFA Responsible Entity will not nominate nor receive an allocation of ARRs nor be eligible for conversion to FTRs in the annual FTR Auction for the Capacity under the GFA.

ii. Treatment of Transmission Congestion. The Transmission Provider shall charge the GFA Responsible Entity the Cost of Congestion for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Points, or GFA Schedule Receipt Point and GFA Schedule Delivery Points for the Grandfathered Agreement(s), as set forth in Section 39.3.3 and 40.4.

iii. Treatment of Transmission Losses: The GFA Responsible Entity shall be assessed the Marginal Losses Component for all transactions pursuant to the Grandfathered Agreement(s) based on the designated Internal Delivery Points, or the GFA Schedule Receipt Point and GFA Schedule Delivery Point, as set forth in Section 39.3.3 and 40.4. GFA Responsible Entities receiving such assessment for Marginal Losses shall receive an allocation of excess marginal losses revenue based on the Marginal Losses Surplus Share.

38.8.3(A) Treatment of Grandfathered Agreements Added to Attachment P After September 16, 2004.

Grandfathered Agreements added to Attachment P of the Tariff after September 16, 2004 shall be subject to the following treatment:

a. Grandfathered Agreements subject to a just and reasonable standard of review must choose:

i. Option A or Option C treatment under the Tariff; or

ii. Full conversion to service under the Tariff.

b. Grandfathered Agreements shall be carved out of the Energy and Operating Reserve Markets, and shall be subject only to Section 38.8.4 of the Tariff, to the extent that:

   i. They are subject to the public interest standard of review;
   ii. They are silent on the applicable standard of review; or
   iii. They provide for transmission service by an entity that is not a public utility.

However, parties to Carved-Out Grandfathered Agreements may voluntarily choose Option A or Option C treatment under the Tariff, or fully convert to service under the Tariff, as described in Section 38.8.3A.a above. Parties that make such a choice or conversion cannot revert to carved-out status. Notwithstanding the foregoing, carved-out treatment under this paragraph b shall not be available to Grandfathered Agreements added to Attachment P of the Tariff effective on or after November 1, 2009, that involve service to an Affiliate or an owner-member of the Transmission Owner or to an entity that itself is a Transmission Owner. Any such agreements between Transmission Owners shall be fully converted to service under the Tariff for the internal loads of the affected Transmission Owners.

Item KIUC MISO 1-9) ***Please provide an estimate of the incremental amount, stated in dollars, that Big Rivers will be obligated to pay in each year, 2011 through 2015, based on MISO's final grandfathering decision compared to its financial obligation if all the above wholesale contracts had been grandfathered.***

Response) The terms grandfathering and grandfathering decision in questions 8-9 is assumed to refer to Grandfathered Agreements and Treatment of Grandfathered Agreements, under the Midwest ISO's Tariff, including section 38.8.3(A). Module A of the Tariff defines Grandfathered Agreements as An agreement or agreements executed or committed to prior to September 16, 1998 or ITC Grandfathered Agreements that are not subject to the specific terms and conditions of this Tariff consistent with the Commission's policies. These agreements are set forth in Attachment P to this Tariff.

Based on the initial evaluation of the agreements that may qualify as GFAs under the Midwest ISO's Tariff, the Midwest ISO plans a future filing to add any appropriate agreements to Attachment P of the Tariff. Ultimately, the Treatment received will be dependent on the individual agreements and the terms of the Tariff, and must be approved by the Commission as part of an Attachment P filing.

Such Grandfathered Agreements relate to Transmission Service, and as such to the extent any wholesale contracts failed to qualify for Treatment as a GFA, individual customers would convert to standard OATT service. Any financial impact would be limited to the difference between existing service rates and OATT rates, which may not directly impact Big Rivers.

With the exception of Transmission Service rates, and exemption from allocation of RECB charges under the current Schedule 26, Transmission Service receiving Option A or C GFA treatment essentially receive charges and credits consistent with all other types of Transmission Service and associated Market Transactions. As a result, any incremental amounts would equal the difference between RECB Charges allocated to transmission customers taking service under the OATT versus RECB Charges allocated to customers taking service under GFAs. See responses to questions 2.a. and b. of the KPSC Data request for further content related to any RECB charges that may be allocated on GFAs post July 2010.

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-10) *Refer to page 19, line 17 of your testimony. Please provide an explanation of the July 2010 filing date, including the following:*

(a) whether the filing date can be extended and if so, by whom and at whose initiative;

(b) whether the filing date is likely to be extended and why; and

(c) the status of the allocation process if the filing date is extended or not met?

Response) a. Although the Midwest ISO could seek an extension of time to make the compliance filing, granting the extension would be at FERC's discretion.

b. The Midwest ISO has been engaged in extensive analysis and discussion with stakeholders and the state regulatory community on this topic since January, 2009. Consequently, the Midwest ISO does not expect to request an extension and expects to file a revised transmission cost sharing proposal on July 15, 2010.

c. If for some reason the filing date is extended beyond July 15, 2010, the present transmission cost sharing methodology would remain in effect until proposed revisions are filed and accepted by FERC.

Witness) **<u>Clair J. Moeller</u>**

Item KIUC MISO 1-11) ***Please provide the current MTEP operating plan and budget for each of the years 2011 through 2015 with respect to expansion of transmission facilities to the Great Plains region in order to connect wind energy sources to the MISO transmission grid. In your response, please include the following:***

(a)the projected dates or range of dates for each facility expansion;

(b) the projected range of cost for each facility expansion;

(c) the current stage of the approval process for each facility expansion;

(d) a narrative discussion of competing positions among stakeholders within MISO about whether transmission expansion to accommodate wind facilities, generally, should be undertaken by MISO Transmission Owners (TOs), and about how the costs of such facilities should be allocated among stakeholders.

Response) a. Certain transmission upgrades to integrate specific wind generators are currently in the Midwest ISO Transmission Expansion Plan (MTEP). These projects are identified as Generator Interconnection Projects and are identified in Appendix A of the MTEP. However, no large scale transmission projects designed to integrate wind energy resources to the grid are reflected in the current MTEP plan. The Midwest ISO is currently performing a study to determine the best transmission solution to deliver enough energy from renewable resources (predominately wind) to load in order to meet existing state renewable portfolio standards (RPS). This study is called the Regional Generator Outlet Study or RGOS. The RGOS is an open and collaborative planning effort between the Midwest ISO and our stakeholders. Additional study details can be found on the Midwest ISO website through the link to the Renewable Energy gateway which provides an update on the progress of this study.[1] Because the RGOS study is in the transmission project design and alternative evaluation phase, there is neither a definitive plan nor an implementation schedule at this time. However, the Midwest ISO expects the RGOS transmission to be built in a phased in approach over the next 10 to 15 years beginning with transmission projects expected to provide benefit under a wide variety of energy policy outcomes.

b. Because the RGOS is still ongoing, final cost estimates are not available at this time. Currently it is estimated that 15 to 20 billion dollars in new transmission investment may be needed to support state RPS in the Midwest ISO footprint. These projections will change as the planning process evolves, or if there are changes in public policy driving RPS.

c. Because the projects being considered in the RGOS are still in the planning phase they are not yet in the formal approval process. Once the RGOS is completed it is expected that these portfolio of transmission projects identified would be moved into Appendix B of the MTEP. Appendix B projects are projects that are demonstrated to be a potential solution to an identified reliability, policy or other need, or to an identified cost savings or other benefit. The Midwest ISO is targeting the RGOS

[1] http://www.midwestmarket.org/page/Renewable%20Energy%20Study

projects to be in Appendix B for the 2010 MTEP.

The next phase of the approval process would be to move the projects to Appendix A. Appendix A projects are projects that have been justified to be the preferred solution to an identified reliability, policy or other need, or to achieve an identified cost savings or other benefit. To reach Appendix A status, a project must be approved by the Midwest ISO Board of Directors.

d. There is general agreement among many Midwest ISO Transmission Owners and other stakeholders that transmission expansion is needed to integrate new kinds of variable resources (predominately wind) into the Midwest ISO system in order for our stakeholders to be compliant with existing state RPS, as well as maintain reliability and reduce congestion on the system. The majority of states within the Midwest ISO currently have some kind of RPS and there is a potential for a federal RPS at some point in the future. Because of this the need for transmission expansion is well defined and accepted. There is ongoing discussion and varied opinions regarding what kind and size (DC v. AC, 345kV v. 765 kV) of transmission expansion is needed to not only meet current needs but be robust enough that it would provide benefits given the uncertainty around future needs (i.e. Federal RPS, development of nuclear technology, increased demand response resources etc.). The purpose of the RGOS is to evaluate these different options and come up with the best engineering solution(s) to the challenge of integrating large amounts of variable generation into the Midwest ISO system.

The Midwest ISO and our Stakeholders have been engaged in discussions on how the cost of transmission development should be allocated since January of 2009. Some stakeholders feel that broad cost sharing should be limited to unique policy driven projects, and that those costs should be shared equally. Other stakeholders feel that one cost sharing methodology that applies to all transmission expansion is more appropriate.

There are also varied opinions on the specific details of who should pay costs. Should all of the costs be paid directly by load or should some of the costs be carried by generators as a means to target the appropriate end use load? Should transmission revenue requirements be allocated on the basis of voltage, project flow or some combination? Although opinions vary, the Midwest ISO is working very closely with our stakeholders through our Regional Expansion Criteria and Benefits Task Force (RECBTF) and our state commissions through the Organization of Midwest ISO States Cost Allocation and Regional Planning (CARP) group to achieve a cost allocation methodology that will be broadly accepted.

Witness) **Clair J. Moeller**

Item KIUC MISO 1-12) ***Please refer to lines 9-10 of page 9 of your direct testimony. Please provide evidence, including Documents and Studies, that serve as a foundation for the statement "We (MISO) have operated for more than a year under this model with excellent performance." In your answer, please identify criteria by which performance is assessed, and explain how performance is gauged, given predefined measurement criteria.***

Response) The criteria used to determine that Midwest ISO Balancing Authority (BA) operation has achieved excellent performance are the NERC Control Performance Standards. Since the launch of the Midwest ISO ASM market on January 6, 2009, the Midwest ISO has been the Balancing Authority for its entire market footprint. The Midwest ISO has been participating under the NERC Balancing Authority ACE Limit (BAAL) Proof-of-Concept Field Trial for the same period which replaces Control Performance Standard 2 (CPS 2) performance criterion.

From January 6, 2009 to date, Midwest ISO BA has been fully compliant with Control Performance Standard 1 (CPS 1), BAAL and Disturbance Control Standard (DCS) as evidenced in NERC auditable reports to the Regional Entities and NERC.
To date the Midwest ISO has been over 100% Compliant with CPS 1 for every month of BA Operation and currently has a rolling 12 month Average CPS 1 compliance of 134.9%. NERC requires each Balancing Authority to achieve, as a minimum, CPS 1 compliance of 100%. (In the calculation of CPS 1, 100% is the base for compliance, and a percentage above 100% indicates a higher level of performance).

Also to date, as the BA Operator, the Midwest ISO participated in the Midwest Contingency Reserve Sharing Group (CRSG) from Jan 6, 2009 through Dec 31, 2009 and is currently coordinating with Manitoba Hydro under a separate Reserve Sharing Agreement that began Jan 1, 2010. Under the previous Midwest CRSG and the current arrangement with Manitoba Hydro, the Midwest ISO has participated in 9 DCS level events and has been 100% Compliant with DCS for all events.

Finally, the Midwest ISO has been 100% Compliant with BAAL under the Proof-of-Concept Field Trial noted above.

Witness) **David Zwergel**

Item KIUC MISO 1-13) ***Refer to page 10 of your direct testimony. Please identify and explain the "limitations" referred to on line 2 of your direct testimony.***

Response) Under Attachment RR to the Midwest ISO Tariff, Big Rivers pays for Spinning and Supplemental Contingency Reserves as though it is already a load integrated into the Midwest ISO Balancing Authority (BA) Area. Upon loss of resources from within the Big Rivers BA Area, Big Rivers may request that Contingency Reserves be supplied from the Midwest ISO to Big Rivers. These reserves are delivered as energy to the Big Rivers border and are available to be used to meet capacity and operating reserve needs for the Big Rivers BA. However, in order to ensure NERC compliance with BAL-002, Big Rivers is obligated to replace the capacity that was lost within 90 minutes after the end of the Disturbance Recovery Period as defined in BAL-002. Therefore, Big Rivers is obligated to procure replacement energy within 90 minutes from the end of the Disturbance Recovery Period or within 105 minutes from the time of the loss. Under these rules, which are spelled out in Attachment RR, Big Rivers is obligated to take all necessary actions up to and including purchasing Emergency Energy to end the reserve activation assistance within 105 minutes from the time of the initial loss. When Big Rivers becomes a fully integrated member of the Midwest ISO market, the replacement energy will be part of normal market operation and will require no special actions from Big Rivers, the loss of a resource will be covered with the next most economic source that can be supplied to the area from the market via the normal 5 minute security constrained economic dispatch. Furthermore, Big Rivers would not need to purchase Emergency Energy, because this responsibility is assumed by the Midwest ISO BA and would not need to be implemented unless there was a shortage of energy within the much larger Midwest ISO BA Area.

Witness) **David Zwergel**

Item KIUC MISO 1-14) ***Refer to page 10, lines 12 through 13 of your direct testimony. Please provide all documents and data detailing the dates, times of the day, duration in hours and level of TLRs calls that have been called by MISO or other Control Area Operator on flowgates or transmission interties to or with Big Rivers in the past five years.***

Response) Attached is the compilation of TLR activity generated by the Midwest ISO or TVA relating to flowgates or interties to or with Big Rivers from 2005 -2010 based on public information posted on the NERC website at: http://www.nerc.com/filez/Logs/monthlysummaries.htm

Witness) **David Zwergel**

ATTACHMENT 1

Date	FGID	Flowgate	StartTime	ReturnToZero	Duration (hrs)	Highest TLR Level	Highest Priority Transaction Curtailed
1/29/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	1/29/05 11:26	1/29/05 16:28	5.03	3a	0
3/1/2005	2281	Newtonville 138/161 flo Henderson 138/161	3/1/05 8:27	3/1/05 9:31	1.07	3a	0
3/26/2005	12761	Newtonville 138/161 (flo) Wilson - Coleman 345	3/26/05 5:50	3/26/05 11:09	5.32	3a	2
5/15/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/15/05 11:15	5/15/05 21:38	10.38	3a	6
5/17/2005	12916	Newtonville 138/161 xfmr flo Coleman-Wilson 345	5/17/05 7:45	5/17/05 15:36	7.85	3a	6
5/18/2005	12916	Newtonville 138/161 xfmr flo Coleman-Wilson 345	5/18/05 7:35	5/18/05 20:31	12.93	3a	6
5/19/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/19/05 10:43	5/19/05 22:52	12.15	3a	6
5/24/2005	12916	Newtonville 138/161 xfmr flo Coleman-Wilson 345	5/24/05 6:33	5/24/05 13:46	7.22	3a	6
5/25/2005	12916	Newtonville 138/161 xfmr flo Coleman-Wilson 345	5/25/05 6:30	5/25/05 14:27	7.95	3a	6
5/25/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/25/05 15:40	5/25/05 21:31	5.85	3a	6
5/26/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/26/05 9:44	5/26/05 19:27	9.72	3a	5
5/29/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/29/05 13:28	5/29/05 21:56	8.47	3a	6
5/30/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/30/05 10:36	5/30/05 20:42	10.10	3a	5
6/9/2005	2954	Wilson-Green River 161	6/9/05 7:36	6/9/05 9:31	1.92	3a	0
6/18/2005	2421	Hopkin Co.-Barkley 161 (flo) Wilson-Green River 161	6/18/05 14:27	6/18/05 21:39	7.20	3a	6
7/13/2005	2281	Newtonville 138/161 flo Henderson 138/161	7/13/05 23:07	7/14/05 13:46	14.65	3b	6
7/14/2005	2026	10NEWTVL 161 14COLE 5 161	7/14/05 23:26	7/15/05 13:44	14.30	3a	6
7/14/2005	2281	Newtonville 138/161 flo Henderson 138/161	7/14/05 23:33	7/15/05 4:10	4.62	3a	6
7/22/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	7/22/05 22:26	7/23/05 4:25	5.98	3a	6
7/23/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	7/23/05 23:34	7/24/05 2:35	3.02	3a	6
7/29/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	7/29/05 21:14	7/30/05 1:50	4.60	3b	6
7/30/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	7/30/05 4:36	7/30/05 19:20	14.73	3a	6
7/30/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	7/30/05 21:16	7/31/05 0:27	3.18	3b	6
7/31/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	7/31/05 8:29	7/31/05 22:36	14.12	3a	6
8/2/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	8/2/05 3:32	8/2/05 5:28	1.93	3a	2
8/4/2005	2194	14N.HAR4 138 14N.HAR5 161	8/4/05 8:18	8/4/05 17:52	9.57	3b	6
8/9/2005	2281	Newtonville 138/161 flo Henderson 138/161	8/9/05 22:26	8/10/05 0:40	2.23	3b	6
8/9/2005	2295	A. B. Brown-Henderson 138 flo Culley-Grandview 138	8/9/05 23:07	8/10/05 6:37	7.50	3b	6
8/9/2005	2194	14N.HAR4 138 14N.HAR5 161	8/9/05 23:18	8/10/05 6:37	7.32	3a	0
8/10/2005	2194	14N.HAR4 138 14N.HAR5 161	8/10/05 23:11	8/11/05 3:34	4.38	3a	0
8/10/2005	13120	Newtonville-Coleman 161 (flo) Henderson 138/161	8/10/05 23:44	8/11/05 0:27	0.72	3b	2
8/13/2005	2281	Newtonville 138/161 flo Henderson 138/161	8/13/05 8:39	8/13/05 15:32	6.88	3a	6

Date	FGID	Flowgate	StartTime	ReturnToZero	Duration (hrs)	Highest TLR Level	Highest Priority Transaction Curtailed
8/14/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	8/14/05 22:24	8/14/05 22:27	0.05	3a	6
9/27/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	9/27/05 2:51	9/27/05 13:32	10.68	3a	6
9/29/2005	2295	A. B. Brown-Henderson 138 flo Culley-Grandview 138	9/29/05 15:06	9/29/05 22:38	7.53	3b	6
10/10/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	10/10/05 4:45	10/10/05 19:50	15.08	3a	2
10/10/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	10/10/05 22:30	10/11/05 3:26	4.93	3a	6
10/21/2005	2295	A. B. Brown-Henderson 138 flo Culley-Grandview 138	10/21/05 22:40	10/22/05 0:13	1.55	3a	2
11/6/2005	2026	10NEWTVL 161 14COLE 5 161	11/6/05 9:14	11/6/05 11:17	2.05	3a	0
11/11/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	11/11/05 6:56	11/12/05 0:30	17.57	3a	6
11/12/2005	13250	Newtonville 138/161 xfmr (flo) Troy-Newtonville 161	11/12/05 2:44	11/13/05 0:03	21.32	3a	6
11/23/2005	2295	A. B. Brown-Henderson 138 flo Culley-Grandview 138	11/23/05 10:20	11/23/05 23:11	12.85	3b	6
11/23/2005	2281	Newtonville 138/161 flo Henderson 138/161	11/23/05 21:08	11/24/05 0:08	3.00	3b	6
11/25/2005	2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	11/25/05 22:15	11/26/05 3:32	5.28	3b	6
11/27/2005	13250	Newtonville 138/161 xfmr (flo) Troy-Newtonville 161	11/27/05 13:28	11/28/05 1:45	12.28	3a	6
12/6/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	12/6/05 8:45	12/6/05 18:27	9.70	3a	6
12/6/2005	2528	Culley-Grandview 138 (flo) Henderson 138/161	12/6/05 20:31	12/6/05 23:30	2.98	3a	6
12/16/2005	2281	Newtonville 138/161 flo Henderson 138/161	12/16/05 21:38	12/16/05 23:30	1.87	3a	6
12/17/2005	2281	Newtonville 138/161 flo Henderson 138/161	12/17/05 12:40	12/18/05 12:39	23.98	3a	5
12/24/2005	2281	Newtonville 138/161 flo Henderson 138/161	12/24/05 11:30	12/24/05 18:28	6.97	3a	5
12/27/2005	2281	Newtonville 138/161 flo Henderson 138/161	12/27/05 11:46	12/27/05 17:19	5.55	3a	6
1/6/2006	2281	Newtonville 138/161 flo Henderson 138/161	1/6/06 22:39	1/6/06 23:34	0.92	3a	0
1/17/2006	2528	Culley-Grandview 138 (flo) Henderson 138/161	1/17/06 3:59	1/18/06 17:55	37.93	3a	6
1/22/2006	2528	Culley-Grandview 138 (flo) Henderson 138/161	1/22/06 6:30	1/22/06 20:07	13.62	3a	6
4/22/2006	2281	Newtonville 138/161 flo Henderson 138/161	4/22/06 7:39	4/23/06 2:58	19.32	4	6
5/20/2006	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/20/06 7:45	5/21/06 22:33	38.80	3a	6
5/22/2006	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/22/06 7:41	5/22/06 23:57	16.27	3a	6
5/23/2006	2281	Newtonville 138/161 flo Henderson 138/161	5/23/06 8:29	5/23/06 14:31	6.03	4	6
6/14/2006	2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	6/14/06 11:43	6/14/06 22:53	11.17	3b	6
6/15/2006	2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	6/15/06 22:31	6/17/06 10:06	35.58	4	6
6/20/2006	2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	6/20/06 21:19	6/21/06 1:03	3.73	3a	6
6/27/2006	2528	Culley-Grandview 138 (flo) Henderson 138/161	6/27/06 15:06	6/27/06 17:26	2.33	3a	0
10/23/2006	2281	Newtonville 138/161 flo Henderson 138/161	10/23/06 9:53	10/23/06 11:05	1.20	3b	6
11/9/2006	2194	14N.HAR4 138 14N.HAR5 161	11/9/06 17:54	11/9/06 23:23	5.48	3a	2

Date	FGID	Flowgate	StartTime	ReturnToZero	Duration (hrs)	Highest TLR Level	Highest Priority Transaction Curtailed
11/10/2006	2194	14N.HAR4 138 14N.HAR5 161	11/10/06 8:35	11/10/06 20:26	11.85	3a	6
11/11/2006	2194	14N.HAR4 138 14N.HAR5 161	11/11/06 10:05	11/11/06 14:36	4.52	4	6
11/12/2006	2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	11/12/06 21:31	11/12/06 23:31	2.00	3a	2
12/4/2006	2422	NEW HARDINSBG 138-161/COLEMN-NATAL 161	12/4/06 22:21	12/5/06 6:25	8.07	3b	6
12/8/2006	2194	14N.HAR4 138 14N.HAR5 161	12/8/06 0:34	12/8/06 1:30	0.93	3a	6
12/14/2006	2528	Culley-Grandview 138 (flo) Henderson 138/161	12/14/06 7:31	12/14/06 11:39	4.13	3a	6
3/31/2007	2528	2528_Culley-Grandview 138 (flo) Henderson 138/161	3/31/07 4:46	3/31/07 4:46	0.00	3a	6
3/31/2007	2528	2528_Culley-Grandview 138 (flo) Henderson 138/161	3/31/07 5:26	3/31/07 17:26	12.00	3a	6
4/1/2007	2528	Culley-Grandview 138 (flo) Henderson 138/161	4/1/07 10:57	4/1/07 22:35	11.63	3a	6
4/3/2007	2281	Newtonville 138/161 flo Henderson 138/161	4/3/07 20:44	4/3/07 23:29	2.75	3a	6
4/9/2007	2295	A. B. Brown-Henderson 138 flo Culley-Grandview 138	4/9/07 21:30	4/9/07 22:28	0.97	3a	6
4/14/2007	2528	Culley-Grandview 138 (flo) Henderson 138/161	4/14/07 14:24	4/14/07 16:04	1.67	3b	6
4/23/2007	2026	10NEWTVL 161 14COLEMN 161	4/23/07 21:29	4/23/07 23:21	1.87	3a	6
5/5/2007	2528	Culley-Grandview 138 (flo) Henderson 138/161	5/5/07 8:01	5/5/07 22:20	14.32	3a	6
5/5/2007	2026	10NEWTVL 161 14COLEMN 161	5/5/07 10:31	5/5/07 22:15	11.73	5a	7
5/6/2007	2026	10NEWTVL 161 14COLEMN 161	5/6/07 8:22	5/6/07 21:07	12.75	5a	7
6/8/2007	3163	Renshaw-Livingston 161	6/8/07 5:20	6/8/07 11:21	6.02	4	6
6/9/2007	3163	Renshaw-Livingston 161	6/9/07 5:38	6/9/07 23:10	17.53	4	6
6/10/2007	3163	Renshaw-Livingston 161	6/10/07 8:15	6/10/07 23:13	14.97	4	6
7/16/2007	2026	10NEWTVL 161 14COLEMN 161 1	7/16/07 22:52	7/17/07 0:59	2.12	3b	6
7/17/2007	2026	10NEWTVL 161 14COLEMN 161 1	7/17/07 21:43	7/18/07 1:59	4.27	3b	6
8/25/2007	2026	10NEWTVL 161 14COLEMN 161 1	8/25/07 21:29	8/26/07 12:28	14.98	3a	6
8/26/2007	14600	Newtonville - Coleman 161 (flo) Wilson - Coleman 345	8/26/07 11:24	8/26/07 21:02	9.63	3b	6
9/1/2007	14600	Newtonville - Coleman 161 (flo) Wilson - Coleman 345	9/1/07 11:47	9/4/07 0:36	60.82	4	6
9/18/2007	14644	Newtonville - Coleman 161 (flo) Coleman - Wilson 345	9/18/07 20:45	9/19/07 1:47	5.03	4	6
10/11/2007	2026	10NEWTVL 161 14COLEMN 161 1	10/11/07 19:51	10/12/07 23:47	27.93	4	6
11/12/2007	2026	10NEWTVL 161 14COLEMN 161 1	11/12/07 0:51	11/12/07 3:36	2.75	3a	6
1/9/2008	2421	Hopkin Co.-Barkley 161 (flo) Wilson-Green River 161	1/9/08 7:11	1/9/08 18:19	11.13	3b	6
3/29/2008	2528	Culley-Grandview 138 (flo) Henderson 138/161	3/29/08 0:16	3/30/08 23:44	47.47	3a	6
6/6/2008	15129	Reid - Daviess 161 (flo) Wilson - Davies 345	6/6/08 7:56	6/6/08 22:28	14.53	3a	6
1/2/2010	2077	A. B. Brown-Henderson 138	1/2/10 6:34	1/2/10 13:04	6.50	3a	6

Item KIUC MISO 1-15) ***Refer to page 12, lines 9 through 13 of your direct testimony. Please explain what differences there would be in MISO's regional reliability planning process and planning coordination if Big Rivers was a member versus the status quo case wherein Big Rivers is not a member.***

Response) There would be several modifications to the Midwest ISO planning process that would result in benefits to Big River's customers. The Midwest ISO planning process would integrate the most current system facility data and planning models of Big Rivers into the regional planning processes that cover the short range planning periods of days, to the long term planning horizons of ten years and beyond. Although the Midwest ISO currently coordinates with adjacent entities in compliance with the inter-regional planning principles of FERC Order 890, the seamless integration of the systems results in a more frequent and efficient level of coordination. For example, while protocols for inter-regional planning call for periodic exchange of planning information and coordinated system studies every few years, planning coordination as a member system would cover all time frames from daily operational planning coordination to the annual regional plan development that covers the ten year planning horizon and beyond. Operational planning, among other things, involves coordination between member systems of planned maintenance outages of facilities. This coordination will prevent planned outages of facilities on adjacent utility systems from having negative reliability impacts on the Big Rivers system. The annual MTEP planning process, reviews the mutual effects of all planned facilities of member systems so that plans are adjusted as necessary to prevent reliability problems due to loop flow impacts of adjacent system facilities from occurring on any member system. In addition, plans are reviewed in aggregate to see if efficiencies can be gained by combining individual system plans into more efficient solutions. As Planning Authority, the Midwest ISO also ensures and demonstrates annually through its regional planning process that all member systems are planned in accordance with the reliability planning standards of the National Electric Reliability Council. The regional planning process also addresses congestion that reduces market efficiency. Congestion planning addresses system improvements that may be beneficial in permitting a more efficient dispatch and lowering the cost of delivered energy when these cost savings justify the system improvements. This energy delivery efficiency analysis would be applied to the Big Rivers system together with the other member systems comprising the market. The Midwest ISO Order 890 compliant planning process ensures that all member system stakeholders have an opportunity to better understand and provide input to proposed plans as they are developing, so that system enhancements may be tailored to best address customer needs. Big Rivers transmission customers and other stakeholders will be able to take advantage of these open and transparent processes on a continuous basis that addresses both reliability and market efficiency needs.

Witness) **<u>David Zwergel</u>**

Item KIUC MISO 1-16) ***Refer to page 14, lines 6 through 20 of your direct testimony. What was the relationship between day-ahead congestion revenue collections by MISO and day-ahead congestion obligations to FTR holders in MISO in 2006, 2007 and 2008? Were congestion revenues collected by MISO sufficient to cover the congestion payments made by FTR holders in the three years 2006, 2007 and 2008?***

Response) The Congestion revenue collected from the Day Ahead Market is used to fund FTRs. For the years 2006 through 2008, congestion revenues collected by the Midwest ISO in the Day Ahead market were below FTR payment targets. Day Ahead congestion revenues collected were 89.6% of the FTR target of $510M in 2006, 83.3% of $724M target in 2007, and 88% of $562M target in 2008. The relationship between congestion revenues collected by the Midwest ISO and congestion payments to FTR holders is correlated with, but not equal to, congestion cost incurred by Load Serving Entities ("LSEs"). FTR value is paid to FTR holders whether or not the generator source used to serve LSE load matches an FTR source. Under least-cost regional dispatch, generation from sources other than the FTR source will be utilized only when it is cost effective. As a result, FTR value may exceed congestion costs incurred for a particular FTR source and sink path. Therefore, the underfunding of FTRs may not equate to unhedged congestion. In addition, FTR holders receive revenues to offset congestion costs from sources other than FTRs. Specifically, in addition to FTR revenues realized from the Day-Ahead market, LSEs receive an allocation of FTR/ARR auction revenue. Including the ARR revenues, Market Participants were funded at 96.7% in 2008 and 100.8% in 2009 after the transition from the FTR to the ARR/LTTR market mechanism.

Witness) **Richard Doying**

Item KIUC MISO 1-17) ***Refer to lines 16-22 of page 17, and lines 1-3 of page 18 of your testimony. Does the Long-Term Resource Assessment of reserves that you cite suggest that Big Rivers is likely to be able to obtain, across the region as broadly defined, contingency reserves from others over this timeframe?***

Response) Yes. The current 2010 LOLE report projects the 10-year out planning reserve requirement of about 15%. The current study reflects an aggregate system wide deliverability of over 98% of Midwest ISO Capacity Resources to Midwest ISO load. The most recent LOLE study does not determine if Planning Reserves will be deliverable to Big Rivers and additional studies, including interconnection studies or transmission service request studies will be needed to establish deliverability of planning reserves to Big Rivers' load. Based on the prior studies, the Midwest ISO expects that Big Rivers will likely be able to procure planning resources from across the broad Midwest ISO region.

Witness) **<u>Richard Doying</u>**

Item KIUC MISO 1-18) ***Refer to lines 16-21 of page 18, and lines 1-2 of page 19 of your direct testimony. Please provide Documents and Studies, including workpapers, used by MISO for the determination of the Cost of New Entry (CONE).***

Response) The Midwest ISO works closely with the Independent Market Monitor ("IMM") in developing estimates of CONE. The IMM uses these estimates of CONE in his annual 'State of the Market' report that he files with the Midwest ISO Board and FERC to assess the odds that certain resource types participating in the Midwest ISO Markets can achieve enough revenues to cover expected costs. CONE estimates are used as a value of new investment in generation resources. These estimates of CONE have been filed and justified with the FERC: see the below excerpt from the Midwest ISO Compliance Filing in FERC Docket No. ER08-394-003 filed on November 19, 2008 (pages 5-10) as one such example:

"In response to the Commission's directive, the Midwest ISO has reviewed the methodology used in other RTOs/ISOs, as well as, consulted with the IMM regarding the CONE value. The current CONE value of $80,000/MW-year was estimated by the Midwest ISO's IMM for use in their 2007 State of the Market Report. This CONE value is based on the overnight capital costs with a five percent contingency factor and the fixed operating and maintenance costs for a conventional combustion turbine built in the Midwest ISO Region developed by the Energy Information Administration for the 2008 Annual Energy Outlook."

"These values were stated in 2006 dollars so the IMM inflated the costs by 6.5 percent to report them in 2008 dollars. To include additional factors that were not included in the overnight capital costs, the IMM included an additional 7.5 percent to reflect financing costs and the carrying cost of working capital. Taken together, the IMM assumed capital costs of $555 per kw and fixed operating and maintenance of $12.55 per kw-year."

"In order to produce the annualized CONE from these cost numbers, the IMM assumed a 50/50 debt to equity ratio, 15 year depreciation, 20 year project life and loan term, 7 percent loan interest rate, 3 percent escalation factor, 2.5 percent GDP deflator, 43 percent combined federal and state tax rate, and 12 percent return on equity. These assumptions are comparable to the assumptions used by other RTOs in the development of CONE estimates and produce a levelized CONE value of $80,000/MW-year."

Witness) **<u>Richard Doying</u>**

ATTACHMENT 1

Midwest ISO
Energizing the Heartland

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November 19, 2008

VIA HAND-DELIVERY

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20246

Re: Compliance Filing of Midwest Independent Transmission System Operator, Inc., regarding Resource Adequacy Requirements Financial Settlements; FERC Docket No. ER08-394-003

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, Part 35 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35, *et. seq*., and in compliance with the Commission's October 20, 2008 Financial Settlement Order[1] regarding the Midwest Independent Transmission System Operator, Inc.'s ("Midwest ISO") Resource Adequacy Requirements ("RAR") Financial Settlements proposal, the Midwest ISO respectfully submits an original and five (5) copies of proposed revisions to its Open Access Transmission and Energy Markets Tariff ("EMT" or "Tariff") to comply with the Commission's directives in the Financial Settlement Order.

I. BACKGROUND

The Midwest ISO filed a proposal for a two-phased approach to permanent resource adequacy on June 6, 2006, in response to several orders from the Commission directing such compliance.[2] On September 26, 2006, the Commission accepted the Midwest ISO's proposed phased approach[3] and on February 15, 2007, the Midwest ISO filed Phase I, as well as a proposal of milestones for filing Phase II of its long term resource adequacy proposal. On December 28, 2007, the Midwest ISO filed its Phase II RAR proposal as set forth in Module E of the EMT.

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[1] *Midwest Independent Transmission System Operator, Inc.*, 125 FERC ¶ 61,060 (2008) ("Financial Settlement Order").

[2] *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (2004); *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,157 (2004); *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,043 (2005).

[3] *Midwest Independent Transmission System Operator, Inc.*, 116 FERC ¶ 61,292 (2006).

On March 26, 2008, the Commission issued an order conditionally accepting the Midwest ISO's December 2007 RAR filing, and directing the Midwest ISO to submit two compliance filings; one within 60 days of the March Order (May Compliance) and one within 180 days (Financial Settlements Compliance).[4] The Midwest ISO made these compliance filings, on May 27, 2008 and June 25, 2008,[5] respectively. Numerous parties filed comments, and Requests for Rehearing, including the Midwest ISO and on October 20, 2008, the Commission issued its order conditionally accepting the Midwest ISO's Financial Settlement proposal.[6] In addition, the Commission issued two related orders in response to the Requests for Rehearing and the Midwest ISO May 27 Compliance Filing,[7] which the Midwest ISO is addressing in two additional, separate compliance filings, which are being filed concurrently with this compliance filing at the Commission today.

II. COMPLIANCE ISSUES

A. Planning Reserve Zones

Hoosier Energy Rural Electric Cooperative, Inc. and Southern Illinois Power Cooperative (collectively "Hoosier/SIPC"), as well as, the Midwest TDUs argue in their comments "that the minimum MW requirements for planning zones, specified in the Midwest ISO's draft Business Practices Manuals ("BPMs"), should be included in the tariff since this provision implicates a rate paid by market participants for resource deficiencies."[8] The Commission agreed with commenters explaining that it considers "a minimum MW specification for reserve zones to be a significant factor impacting the cost of resource deficiencies for LSEs." Therefore, the Commission required that the Midwest ISO "propose a planning zone minimum MW specification" in its Tariff, and not just the BPMs.[9]

In response to the Commission's directives, the Midwest ISO has modified section 68.1.2 to specify a minimum MW specification for planning zones.[10] Specifically, the Midwest ISO proposes to modify section 68.1.2 of the Tariff to state: "Zone size will be a determining factor in the formation of congested Zones. Both positive, or negative MCC Zones as referenced in Step 5, qualify as a Zone to be defined in the LOLE [Loss of Load Expectation] program if the Zone contains either a modeled peak load value of at least 2,000 MW, or contains at least 2,000 MW of modeled generation."

[4] *Midwest Independent System Operator, Inc.*, 122 FERC ¶ 61,283 (2008) ("March 26 Order").
[5] *Midwest Independent System Operator, Inc.*, Financial Settlement Compliance Filing, Docket No. ER08-394-003, (June 25, 2008) ("Financial Settlement Filing").
[6] Financial Settlement Order at P 1.
[7] *Midwest Independent System Operator, Inc.*, 125 FERC ¶ 61,062 (2008).
[8] Financial Settlement Order at P 161.
[9] *Id.* at P 167.
[10] First Revised Sheet Nos. 1445 and 1446.

The minimum 2,000 MW proposal is based on an approach of setting the size of a zone at a fixed percentage of Midwest ISO peak (for example, 2% would be a consistent method, rather than a fixed MW cutoff or all future years).

The Midwest ISO, working with its stakeholders during Supply Adequacy Working Group ("SAWG") meetings, developed the 2,000 MW minimum zonal requirement based on the following factors:

- Minimum Value: A value of 1,000 MW should be considered the low end, because the North American Electric Reliability Corporation ("NERC") provides that a disturbance under that amount is not deemed to have regional significance. The 1,000 MW point is where a disturbance category transitions from concern as a simple Security Operating Limit ("SOL") for amounts of load affected under 1,000 MW to a Transmission Emergency Alert ("TEA").
- Total Number of Modeled Zones: Previous discussions with the SAWG and experience with the use of the process in the "2011 proof of concept case" revealed that a GE MARS model with about 12 zones would be sufficient to model significant congestion activity in the Midwest ISO. At a minimum, the Midwest ISO will need to quantify the three planning zones per Tariff Attachment FF along with one or two external zones which results in a minimum of five zones required. Allowing some granularity within the present three Attachment FF zones would be consistent with and would support having approximately 12 zones total modeled in the LOLE application.
- Functionality: Both the proof of concept cases and the work on the 2009 planning year to date, illustrate that the minimum 2,000 MW size results in both a suitable mix of very large zones (for example in the 50,000 MW range, and down to the 2,000 MW minimum). As the minimum would be raised, a fair amount of congestion may be screened out, and based on use to date it is estimated that a minimum size of about 10,000 MW would result in defaulting to the Attachment FF zones, and the seeking of congestion zones would become moot. For similar reasons the Ancillary Services Market ("ASM") is currently depicting the need for 7 zones internal to the Market.

B. Load Modifying Resources

The Coalition of Midwest Transmission Customers ("CMTC") argued in its comments that the Midwest ISO's proposed voluntary capacity auction is flawed because it does not "reasonably accommodate demand response resources."[11] In its answer, the Midwest ISO responded that load modifying resources ("LMRs") should qualify as planning resources and that it is developing BPMs to address the deliverability of LMRs.[12] The Commission accepted this

[11] Financial Settlement Order at P 49.
[12] *Id.* at P 50.

commitment from the Midwest ISO to develop deliverability provisions in the BPM, but directed the Midwest ISO to explain in its compliance filing how it will determine the deliverability of LMRs.[13]

The Midwest ISO currently proposes to determine the deliverability of LMRs by applying similar universal deliverability analyses used to determine if a Generation Resource can qualify for Network Resource Interconnection Service. The Midwest ISO began discussions on the deliverability of LMRs at the November 4, 2008 Demand Response Working Group ("DRWG") meeting. Discussions with stakeholders centered around the following issues. If an LSE is meeting its RAR obligations with Resources that have been deemed universally deliverable, then using an LMR as a load reduction frees up the universally deliverable Resource to meet other LSEs' needs in the energy balance. Hence, the LMR should be qualified to participate in the auction. While this aspect of LMR deliverability has some appeal, the Midwest ISO does not believe that all aspects and consequences of this potential market design change have been fully studied and vetted by the Midwest ISO and its stakeholders. The Midwest ISO intends to further address how LMRs can be granted universal deliverability status through the stakeholder process and may propose changes to the Tariff and/or the Business Practice Manuals as may be necessitated by such discussions.

C. Voluntary Capacity Auction

Each month the Midwest ISO proposed to conduct a voluntary capacity auction to assist LSEs in meeting their resource adequacy plans with Planning Resources. The Midwest ISO explained in its Financial Settlements Compliance Filing that the auction is intended to complement bilateral transactions, not replace them.[14] In their comments, Reliant Energy, Inc. ("Reliant") suggested that the Tariff be revised to make clear that capacity associated with uncleared offers in the auction may be sold bilaterally following the close of the auction.[15] In its answer, the Midwest ISO clarified that any party may engage in bilateral contracting for resources that did not clear in the voluntary auction.[16] Although the Commission accepted the Midwest ISO's proposal for a monthly,[17] voluntary auction, the Commission also directed the Midwest ISO to clarify that capacity not taken in the auction may be sold bilaterally.[18]

The Midwest ISO has modified section 69.3.9.a.i, as directed by the Commission, to make clear that the capacity that is not procured during the voluntary auction may be sold bilaterally.[19]

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[13] *Id.* at P 54.
[14] Financial Settlement Filing at p. 9.
[15] Financial Settlement Order at P 26.
[16] *Id.* at P 34.
[17] *Id.* at P 36.
[18] *Id.* at P 42.
[19] First Revised Sheet No. 1508.

In their comments, the Wisconsin Public Service Corporation and the Upper Peninsula Power Company ("WPSC/UPPCO") argued that the Midwest ISO failed to address in its compliance filing how external resources can participate in the voluntary capacity auction and whether there will be additional requirements or restraints on the participation of external resources.[20]

While the Commission found the deliverability requirement in the voluntary capacity auction reasonable, in response to the concerns of WPSC/UPPCO, the Commission directed the Midwest ISO to clarify how external resources will participate in the voluntary auction and whether there will be any additional constraints on their participation.[21]

In response, the Midwest ISO herein describes how External Resources may participate in the voluntary auction. The Midwest ISO currently proposes to allow an External Resource to participate in the voluntary capacity auction by meeting the same requirements for an External Resource to qualify as a Capacity Resource in sections 69.2.1.3 b. and 69.2.1.3.c. The Market Participant must demonstrate to the Midwest ISO that it has sufficient firm transmission service to deliver the capacity to the Midwest ISO transmission system from the External Resource, and have Firm Transmission Service to deliver capacity on the Midwest ISO transmission system to a load. The firm transmission service must overlap the planning month the market participant offers the capacity into the voluntary capacity auction.

This is the same requirement for an External Resource to qualify as a Capacity Resource, likewise a Internal Generation Resource that has Network Resource Interconnection Service and passed the universal delivery test will qualify for the auction. External Resources do not qualify for Network Resource Interconnection Service since they are not interconnected to the Midwest ISO Transmission System.

D. Cost of New Entry Value

In the June 25 Financial Settlements Filing, the Midwest ISO proposed to use an initial Cost of New Entry ("CONE") value of $80,000/MW-month and assess it to the deficient LSE for each month's deficiency. In addition, the Midwest ISO proposed to re-evaluate the CONE value annually, based on an analysis that includes the Independent Market Monitor ("IMM").[22] The IMM filed comments that the initial CONE value is for a peaking resource that is included in the 2007 State of the Market Report and that the IMM "supports the use of this value based on information developed by Energy Information Administration regarding the typical costs of

[20] Financial Settlement Order at P 48.
[21] *Id.* at P 53.
[22] Financial Settlement Order at P 57.

investment in new generation resources."[23] Several other parties filed comments arguing that the Midwest ISO has not justified the $80,000 initial CONE value that it has proposed.[24]

The Commission agreed with commenters and found that the Midwest ISO had not sufficiently justified the initial CONE value of $80,000 and directed the Midwest ISO to "further justify the calculation" in a compliance filing "including a detailed description of the process for determining the CONE value, the input data, and the assumptions used to derive the CONE value."[25] The Commission also directed the Midwest ISO to compare its proposed methodology with the methodology of other RTOs, such as PJM.[26]

In response to the Commission's directive, the Midwest ISO has reviewed the methodology used in other RTOs/ISOs, as well as, consulted with the IMM regarding the CONE value.

The current CONE value of $80,000/MW-year was estimated by the Midwest ISO's IMM for use in their 2007 State of the Market Report. This CONE value is based on the overnight capital costs with a five percent contingency factor and the fixed operating and maintenance costs for a conventional combustion turbine built in the Midwest ISO Region developed by the Energy Information Administration for the 2008 Annual Energy Outlook.[27] These values were stated in 2006 dollars so the IMM inflated the costs by 6.5 percent to report them in 2008 dollars. To include additional factors that were not included in the overnight capital costs, the IMM included an additional 7.5 percent to reflect financing costs and the carrying cost of working capital. Taken together, the IMM assumed capital costs of $555 per kw and fixed operating and maintenance of $12.55 per kw-year.

In order to produce the annualized CONE from these cost numbers, the IMM assumed a 50/50 debt to equity ratio, 15 year depreciation, 20 year project life and loan term, 7 percent loan interest rate, 3 percent escalation factor, 2.5 percent GDP deflator, 43 percent combined federal and state tax rate, and 12 percent return on equity. These assumptions are comparable to the assumptions used by other RTOs in the development of CONE estimates and produce a levelized CONE value of $80,000/MW-year.

The Midwest ISO intends to work closely with the IMM and may consider use of an independent consultant to help develop CONE assumptions for future Planning Years under

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[23] *Id.* at P 58.
[24] *Id.* at P 59.
[25] *Id.* at P 74.
[26] *Id.*
[27] Based on email transmissions between the IMM and EIA staff in early 2008, where EIA staff made such estimates for each Regional Entity. The Midwest ISO encompasses three Regional Entities including: SERC Reliability Corporation, Midwest Reliability Organization and Reliability*First* Corporation.

Module E. This work would then be reviewed with Midwest ISO stakeholders prior to filing with the Commission. This approach is consistent with the process currently used to determine CONE at ISO New England ("ISO-NE), New York ISO ("NYISO"), and PJM Interconnection, Inc. ("PJM"). Although it is premature to speculate on the shape this effort will take, it is expected to be similar to the studies undertaken by consultants for the eastern RTOs/ISOs. A high level review of the critical factors necessary for future estimates of CONE was outlined at the SAWG meeting on June 11, 2008.[28]

As directed by the Commission in the Financial Settlements Order, the Midwest ISO has reviewed and evaluated the CONE values used by other RTOs/ISOs. PJM's Reliability Pricing Model ("RPM") has used a CONE of $72,207/MW-year for all auctions to date. This value was estimated to reflect the levelized capital cost and annual fixed operating and maintenance costs of a combustion turbine plant with two General Electric Frame 7FA turbines in Sub Region 1 (New Jersey). CONE values were also estimated for Sub Region 2 (Maryland) at $74,117/MW-year and Sub Region 3 (Illinois) at $73,866/MW-year.

PJM hired Pasteris Energy to develop these CONE assumptions in 2004. They were estimated after developing an array of assumptions with regard to capital costs ($466.0/kw - $475.30/kw), project evaluation (20 years), debt and equity ratio (50/50), return on equity (12%), loan term (20 years), loan interest rate (7%), MACRS tax depreciation schedule (15 years), federal income tax rate (35%), state income tax rate (9%), general escalation (2.5%), ambient temperature (92 degrees Fahrenheit), and others.

In the October 30, 2008 Capacity Market Evolution Committee, Power Project Management, a consultant for PJM, proposed updated CONE values for the next RPM Auction (2012-2013). Power Project Management updated the analysis performed by Pasteris Energy, and augmented it to take other factors into consideration. For instance, they considered differences in income tax assumptions (9% in New Jersey, 8.25% in Maryland, and 7.3% in Illinois.), Consumer Price Index increases (4-6%), Land Costs (10% decrease), Interest During Construction & Term Loan Interest (6% construction financing and 8% term financing), Equipment Costs (10% decrease), and other factors.

In the November 10, 2008 Capacity Market Evolution Meeting, PJM proposed new CONE values for the next RPM Auction (2012-2013) at $142,443/mw-year for Sub Region 1, $131,806/mw-year for Sub Region 2, and $132,847/mw-year for Sub Region 3.[29]

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[28] *See* http://www.midwestmarket.org/publish/Document/1d6630_11a6da4545e_-7fc80a48324a?rev=1.

[29] Current Economic Condition Review for October 2008 of July 15, 2008, 2008 Update of Cost of New Entry Combustion Turbine Power Plant Revenue Requirements, *available at* http://www.pjm.com/committees/cmec/downloads/20081030-item-04-cone-assumption-review-ct.pdf.

The New York ISO estimates separate CONE for the New York City and Long Island Localities ("NYC" and "LI"), as well as the Rest-of-State region ("ROS"). The maximum value for each ICAP Demand Curve is established as 1.5 times the gross CONE. Gross CONE assumptions utilized in NYISO's ICAP Demand Curves are set forth in the table below. The first column of the table represents the region, either NYC, LI, or ROS; the second represents the type of plant; and the third through sixth show the applicable months (June to August, August to September, September to October and October to November).

Current CONE values, Section 514.1(b) of NYISO's tariff

Maximum ICAP Demand Curve values multiplied by 12 / 1.5

Area	Technology	07-08	08-09	09-10	10-11
ROS	Frame 7	92,320	92,400	99,600	107,360
NYC	LM-6000	186,720	188,080	202,720	218,560
LI	LM-6000	164,400	166,960	180,000	194,000

Similar to the approach in PJM, NYISO hires an independent consultant to develop CONE assumptions. In 2007, an update to this study was performed jointly by several economic consulting firms. NYISO's CONE was developed based upon the current localized, levelized, embedded cost of a peaking unit. The NYISO Tariff defines a peaking unit as "the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable." Consequentially, NYISO evaluated the costs of several different types of units, including both frame units (Frame 7EA and Frame 7FA) and aero-derivative units (LM6000 and LMS100).

NYISO's CONE was developed based upon a set of assumptions comparable to those used in the PJM study: the CONE value was estimated after developing an array of assumptions with regard to debt and equity ratio (50/50), return on equity (12%), amortization period (13.5-18.5 years), loan interest rate (7%), federal income tax rate (35%), state income tax rate (7.5%), ambient temperature, and others.[30]

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[30] *See* Proposed NYISO Installed Capacity Demand Curves For Capability Years 2008/2009, 2009/2010 and 2010/2011, *available at* http://www.nyiso.com/public/webdocs/products/icap/demand_curve_documents/demandcurveproposal10-5-2007_final_V2_redlined_101007.pdf; *see also* Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, *available at*

> The CONE value used by ISO-NE is $90,000/MW-month ($7.50/kW-month), and is based upon a negotiated settlement. This CONE value will not be updated over time. Instead, ISO-NE will gradually transition to a market-based approach for determining their Start of Auction Price. Unlike the auctions of NYISO and PJM, ISO-NE's auction design is based upon a Dutch auction, with 2 times CONE being the initial price in the first Forward Capacity Auction. A more precise description of their methodology is contained in the ISO-NE tariff. [31]

As explained above, the Midwest ISO proposed to assess the $80,000 CONE value for each month of the LSE's deficiency. The Commission rejected this proposal to charge the annual CONE for each month's deficiency and concluded that it "would be excessive if applied to an LSE with deficiencies in multiple months."[32] Therefore, the Commission directed "the Midwest ISO to propose more granular monthly deficiency charges that are tailored to deter deficiencies without being excessive on a monthly or cumulative basis" and "to consider whether the monthly deficiency charges proposed by the OMS or the Midwest TDUs achieve these objectives."[33]

The Midwest ISO met on more than one occasion with stakeholders during SAWG meetings to discuss appropriate deficiency charges. The discussions began with the proposals put forth by the Organization of MISO States and the Midwest TDUs, with particular emphasis on the level of the financial charge for the first occurrence by the LSE of a deficiency, the appropriate shaping of the charge to reflect supply/demand conditions during the Planning Year and the cumulative impact of potential charges during any Planning Year. Additional proposals were presented by the Reliant/Integrys and others. and Duke. As a result, the Midwest ISO has modified section 69.3.7 to provide that for the first month during any Planning Year that an LSE is deficient, it will be charged 100% of the CONE value.[34] If the LSE is deficient again by an amount less than or equal to the maximum of any previous monthly deficiency during a Planning Year, the financial settlement charge will be 25% of the CONE value if the deficiency occurs in July or August. During the winter months of December, January and February, the financial settlement charge will be 25% of the CONE value. For any subsequent deficiency during any other month during a Planning Year, the LSE will be assessed a financial settlement charge of

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http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2007-07-16/ICAPWG_Demand_Curve_Study_Report_71607_revised.pdf; *and see* NYISO's ICAP Working Group, "cell range B68:D68 of "Current Curve" tab of spreadsheet file, *available at* http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2007-12-10/ICAP_Demand_Curve_Model_v75_113007.xls.

[31] Source: ISONE Tariff, Section III.13.2.4, *available at* http://www.iso-ne.com/regulatory/tariff/sect_3/08-9-22_-v11-mr1-13-14.pdf

[32] Financial Settlement Order at P 97.

[33] *Id.* at P 100.

[34] First Revised Sheet No. 1505.

8.3% of the CONE value. If an LSE has an increase in its deficient MW amount greater than any previous maximum monthly amount for the planning year, this incremental amount above the previous maximum monthly deficient MW amount will be assessed Annual CONE as it is the first occurrence at the new deficient level.

This revised financial settlement charge proposal is designed to create incentives for LSEs to procure sufficient capacity to meet its load obligations yet not be overly excessive to create an incentive for overbuilding. For the first occurrence of a deficiency, the charge reflecting the annual CONE amount will serve as an incentive for LSEs to meet its resource adequacy obligations and is not intended to serve as a proxy for market prices in the bilateral capacity market. The reduced financial charges during the summer and winter months of 25% of annual CONE for subsequent deficiencies reflects the greater emphasis on the need for adequate resources during higher demand months while mitigating the cumulative impact an LSE would incur if the LSE was deficient in consecutive months. During the Fall and Spring months, the LOLE study typically shows insignificant LOLPs so the financial charge is reduced to 1/12 of annual CONE, or 8.3%. If an LSE is deficient for the entire Summer period fro the Planning Year, the exposure to financial charges would max out at 150% of CONE.

E. Allocation of Financial Settlement Charges

In its Financial Settlement Filing, the Midwest ISO proposed to distribute the revenues from financial settlement charges to LSEs that met or exceeded their RAR.[35] In addition, the Midwest ISO proposed to use the revenues from the financial settlement charges to procure capacity in least cost order, from suppliers that offered but were not selected in the voluntary auction.[36]

Although the Commission found it appropriate for the Midwest ISO to distribute financial settlement revenues to all LSEs that met their RAR on a *pro rata* basis, the Commission rejected "the Midwest ISO's proposal to procure additional capacity resources from resources not selected in the voluntary auction," and directed "the Midwest ISO to allocate deficiency revenues to the LSEs fulfilling their capacity obligations."[37] As required by the Commission, the Midwest ISO has modified section 69.3.9.a.i of the Tariff to remove the language allowing the Midwest ISO use financial settlement revenues to procure additional capacity not taken in the voluntary auction.[38]

In response to the concerns of Duke that Financial Settlement revenues be distributed across all eligible LSEs in the Midwest ISO footprint,[39] the Commission directed the Midwest

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[35] Financial Settlement Filing at p. 11.
[36] Financial Settlement Order at P 119.
[37] *Id.* at PP 131, 132.
[38] First Revised Sheet No. 1507.
[39] Financial Settlement Order at P 124.

ISO to confirm that it intended "that the determination of whether an LSE has met or exceeded its resource adequacy requirements will be based on a zonal determination of resource adequacy."[40] The Midwest ISO hereby confirms that it will determine whether an LSE has met or exceeded its RAR based on a zonal determination of resource adequacy.

In response to Wisconsin Electric Power Company's ("Wisconsin Electric") request for clarification, the Commission directed the Midwest ISO to clarify "whether the term 'peak load' referenced in section 69.3.9 refers to the peak load during the month or during the year."[41] The Midwest ISO hereby clarifies that the term 'peak load' as used in section 69.3.9 was meant to refer to peak load during the month. In addition, the Midwest ISO has modified section 69.3.9 to provide further clarification.[42]

In response to the concerns expressed by Wisconsin Electric regarding the application of deficiency charges during forced outages,[43] the Commission directed "the Midwest ISO to clarify for Wisconsin Electric the application of the deficiency charge in the event that the market participant has a forced outage in the five days between the voluntary auction and the beginning of the resource adequacy requirement."[44]

The Midwest ISO hereby clarifies the application of the deficiency charge as directed by the Commission. An LSE that has identified a qualified Planning Resource in its Resource Plan or has obtained capacity through the voluntary capacity auction is not subject to Financial Settlement Charges when the resource is out of service, provided the Planning Resource has been reported as out of service or de-rated to the Midwest ISO. An owner of qualified Planning Resources that have been identified in an LSE's Resource Plan or who has sold capacity through the voluntary capacity auction is not subject to Financial Settlement Charges.

The Planning Reserve Margin ("PRM") determined through the Loss of Load Expectation ("LOLE") study process takes into account the probability of Capacity Resource outages. On-going generation outage coordination studies are used to monitor and control the total generation capacity available to the Midwest ISO in advance of the operating day. The PRM, in conjunction with generation and transmission maintenance outage coordination, will probabilistically assure that sufficient capacity, even with outages, will be available in the operating day to cover demand plus operating reserves. For these reasons Planning Resources that are reported to the Midwest ISO as out of service are not disqualified as Planning Resources and are not ineligible to satisfy the Resource Adequacy Requirements of an LSE that has identified the Planning Resource in its Resource Plan.

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[40] *Id.* at P 134.
[41] *Id.* at P 135.
[42] First Revised Sheet No. 1507.
[43] Financial Settlement Order at P 83
[44] *Id.* at P 102.

F. Role of the Independent Market Monitor

In response to the concerns of Ameren, CMTC, and others regarding the role of the Independent Market Monitor in the voluntary capacity auction,[45] the Commission found that section 69.3.5.h of the proposed Tariff does not adequately describe the role of the IMM in mitigating market power. Therefore the Commission directed the IMM to: (1) "explain in general terms how it intends to monitor market power in the voluntary capacity auctions and describe – without disclosing specific triggers – under what conditions it would report to the Commission that further modifications are necessary;" and (2) "specify the methods it will use to determine whether market power is being exercised and whether additional mitigation measures are needed, and what additional mitigation measures might look like."[46]

The Midwest ISO understands that the IMM is submitting a separate response to the Commission to address the subject issue.

III. Documents Submitted With This Filing

Pursuant to Section 35.13(b) (1) of the Commission's regulations, below is a list of the documents being submitted with this filing:

Tab A – Redlined Tariff sheets

Tab B – Clean Tariff sheets

IV. Effective Date

The Midwest ISO respectfully requests an effective date of January 6, 2009. This date is consistent with the effective date of the Ancillary Services Market Tariff sheets. The Midwest ISO requests waiver of any applicable provisions of the Commission's rules and regulations to effectuate such a date.

V. Notice and Service

The Midwest ISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the EMT, Midwest ISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, the Midwest ISO Advisory Committee participants, as well as, state commissions within the Region. In addition, the filing has been posted electronically on the Midwest ISO's website at www.midwestmarket.org under the heading "Filings to FERC" for other interested parties in this matter.

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[45] *Id.* at PP 144, 145.
[46] *Id.* at P 155.

VI. CONCLUSION

For the foregoing reasons, the Midwest ISO respectfully requests that the Commission find that the Midwest ISO has complied with the directives contained in the Financial Settlements Order.

Respectfully submitted,

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Michael Donnini, FERC
John Rogers, FERC

Item KIUC MISO 1-19) ***Refer to lines 4-18 of page 19 of your direct testimony. Please provide Documents and Studies, in summary form, which detail the determination of the Loss of Load Expectation (LOLE) at a system level as determined by MISO.***

Response) Under the Module E Resource Adequacy provisions of the Tariff, the Midwest ISO is required to annually study the appropriate Planning Reserve Margin ("PRM"). The most recent two years' reports reflect studies conducted with the current methods and business practices. Each annual report examines a 10-year out horizon. The reports are voluminous to reproduce, but are posted with the following names "2009 LOLE Study" and "2010 LOLE Study" at:
http://www.midwestmarket.org/page/Regulatory%20and%20Economic%20Standards

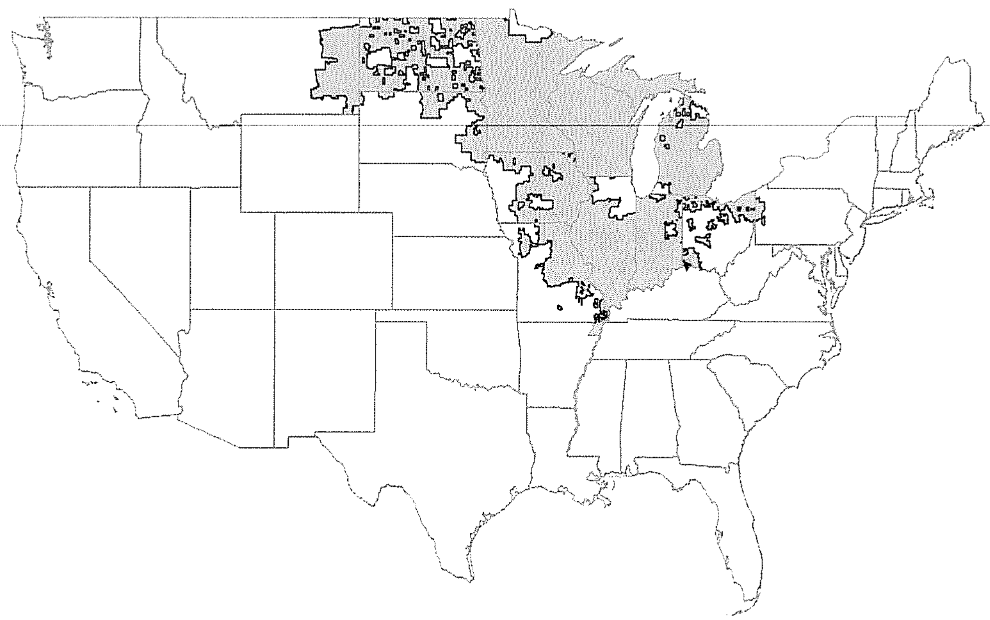
Witness) **Richard Doying**

ATTACHMENT 1

MidwestISO
Energizing the Heartland

Midwest Independent Transmission System Operator, Inc.

2009 – 2010 LOLE Study Report



Midwest ISO Market Footprint

Regulatory and Economic Studies (RES) Department

Table of Contents

1. Executive Summary

An installed reserve margin of 15.4% applied to the Midwest ISO system coincident peak has been established for the planning year starting June 2009 and ending May 2010. This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD IV® was used to perform a security constrained economic dispatch which provided the congestion-driven zonal definitions used within MARS. The analysis also resulted with one uniform Planning Reserve Margin, applicable to the West, Central, and East planning areas that make up the Midwest IOS Market footprint.

Within Module E, individual Load Serving Entities (LSEs) maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 2.35 % diversity factor. This was the lowest diversity experienced on the system since the start of the Midwest ISO energy market and resulted in an individual LSE reserve level of 12.69%, reduced from what would otherwise be a 15.4% reserve without accounting for diversity. An example of applying the results to LSE load is shown in Section 3.3.

The goal of a Loss of Load Expectation (LOLE) study is to determine a level of reserves that would result in the Midwest ISO system experiencing one loss of load event every ten years on average. This equates to a yearly LOLE value of 0.1 days per year or a one in ten chance for a loss of load every year. As modeled within the GE MARS software, the system would achieve this reliability level when the amount of installed capacity available is 1.154 times that of the Midwest ISO system coincident peak.

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group was much appreciated by the Midwest ISO staff involved throughout the process.

2. PROMOD IV® Zonal Analysis

Establishing zones driven by transmission congestion for this LOLE analysis was completed using the PROMOD IV® tool to realistically model the transmission system as it is planned throughout the 2009 – 2010 planning year. This phase of the process both identified zones on the basis of congestion on the transmission system, and quantified restrictions to transfer levels in or out of the zones. The pink boxes on the process map in Section 2.2.4 indicate the PROMOD IV® related activities.

Usage of the word "zone"

- In the context of this 2009 LOLE study report the lower case word "zone" is used extensively in reference to the congestion-driven MCC Zones derived and modeled in the study process. The Tariff has many definitions with modifiers preceding the word Zone. For example Transmission Pricing Zone. The fundamental "Zone" term in the Tariff best reflects the essence of zone as used in this report.

  1.714 Zone: A set of Buses in a geographic area as determined by the Transmission Provider.

- Section 3.1.3 of the Resource Adequacy Requirement (RAR) Business Practice Manual reflects current use of zone and the Planning Reserve Zone term in the Tariff and describes when a different PRM may be applicable to different Planning Reserve Zones:

  1.505 Planning Reserve Zone: The Zone(s) established in Section 68.1 of this Tariff in which an LSE has an RAR obligation.

  All LSE loads subject to the Tariff are subject to one PRM for the 2009 Planning Year. The PRM values along with the total generation and forecast load are shown in Table 4. The three 2009 Planning Reserve Zones (PRZ) conform geographically to three planning areas identified in Attachment FF-3 of the Tariff. The West PRZ corresponds to the modeled zone 4, in. The Central PRZ corresponds to the combination of zones 3, and 7 in Figure 2.2, and the East PRZ corresponds to the combination of zones 1, 2, and 6.

- The very name for the LOLE General Electric (GE) software application GE Multi-Area Reliability Simulation (MARS) and the manual use the term area. Therefore, narrative may transition to the 'area' term when needed to describe certain detail steps in use of the program proper.
- Three 'planning areas' (i.e. East, West, and Central) had been previously identified years before the current Resource Adequacy Requirements in

Module E, as a construct for expansion planning study groups, and certain planning efforts continue to use those planning areas as a means to segregate sub-regional expansion planning topics.

- Those original East, West, and Central planning areas aren't to be mistaken for the congestion-driven MCC Zones (note capital Z) that are determined through the zonal analysis and are utilized by the GE MARS LOLE program.
- The Module E Tariff identifies that congestion-driven Zones are modeled in the LOLE study. The Module E Tariff distinguished further that "A planning Zone (for purposes of determining PRM) will contain no less than 2,000 MW of Load."
- Also for the first LOLE study in 2009, the FERC order indicated that assignment of different PRM's to planning Zones that may come out of the LOLE study, would be limited to determining a different PRM's for Zones that would conform to the original planning areas in Attachment FF-3. The 2009 study results required one uniform PRM for the whole system. The 2009 study was designed and managed to express congestion-driven planning Zones, as they relate to smaller portions of the original East, West, and Central planning areas.

2.1. Construction of PROMOD IV® Model

Load and generating unit data was first imported from PowerBase for utilization in the PROMOD IV® zonal analysis. PowerBase is a commercially available database which is regularly updated by Midwest ISO staff to incorporate Module E submissions such that member-reported load forecasts can be incorporated into studies. The 2009 power flow case was constructed from the Model on Demand (MOD) tool which provides a place for stakeholders to inform Midwest ISO of transmission system conditions and future upgrades. Finally, an EVENT file was created which is used to specify summer and winter line ratings, to designate critical lines for which flows must be monitored and to define potential line-failure or contingency states. The EVENT file was vetted through the Loss of Load Expectation Working Group (LOLEWG) to ensure that all stakeholders had a chance to offer feedback on its contents. The entire Eastern Interconnect was modeled during the PROMOD IV® analysis with non-member systems utilizing the default data from PowerBase and Florida modeled as a fixed transaction due to model limitations. The following sections outline the steps taken to construct the inputs to the PROMOD IV® software.

2.1.1. Updates to PowerBase

Resources within the PowerBase database were updated with information from the Generation Interconnection Queue as of 6-16-08. Generators with a signed Interconnection Agreement were amended to the database, excluding those generators with a suspended status.

For the 2009 Planning Year, the PowerBase fuel price forecasts were updated with the Ventyx June 2008 Fuel Forecast Release.

PowerBase is utilized in the MTEP process and as such contains predicted future generating units utilized to meet planning needs in the MTEP study timeframe. These units were removed from the database to accurately represent the 2009 Planning Year.

2.1.2. Basic PROMOD IV® PowerBase Modeling Assumptions

All nuclear units that were set to retire within the study period (2009-2018) were assumed to be re-licensed and operational. Minimum capacities of coal units were changed in the following manner: Sub-critical coal to 25%, super critical coal to 40%. Supercritical units were identified from the Global Energy Data.
Coal and nuclear units were the only type to have a must run status. Wind units were modeled with a monthly energy profile. Annual capacity factors for all wind units were assumed to be 33% with energy distributed evenly across all months; unless hourly wind profiles were available, in which case the monthly energy profiles were not necessary. Hydro electric units were represented in two groups, as a fixed pattern run-of-river, and as energy-limited that could respond to unit commitment.

2.1.3. Create power flow case from Model on Demand (MOD)

The 2009 Planning Year power flow case was created from MOD with transmission projects phased in according to in-service date.
Refer to Appendix ATransmission Projects in Power-Flow, for a detailed listing of transmission projects included in the Power Flow model.

2.1.4. Event file

In PROMOD IV®, the EVENT file is used to specify summer and winter line ratings, to designate critical lines for which flows must be monitored and to define potential line-failure or contingency states. A "base case" transmission configuration, with no outages at any lines or buses, is part of this data set.

In the events data, the user can specify single or multiple line outages and can monitor simultaneous outages in the system. Each line is matched with an outage state to analyze its impact on the system. While multiple line and outage pairs may be monitored simultaneously, the only restriction is that the user cannot define an outage state which removes every line at a generator bus. Although the program is able to monitor multiple line outages at a bus, there must be at least one line available to distribute power from a generator bus. A bus may not be isolated. There are a finite number of events that can be modeled in the EVENT file.

The primary source of data for the EVENT file was the MISO Book of Flowgates. Since this is a future model, it is necessary to determine any potential future flowgates to be added. A tool called PAT (PROMOD IV® Analysis Tool) is used to help identify the additional flowgates that may occur in the future.

PAT is a tool that works with PROMOD IV. Unlike PROMOD IV® which is primarily utilized for full year simulations, PAT is mainly used for studying a given hour in detail. It reads in the selected hours' information from PROMOD IV®, and solves the same optimization problem for these hours as PROMOD IV®.

However, it provides more information than PROMOD IV®, and allows the user to change the parameters and quickly find out what their influence is on the results. A total of 12 hours were selected ranging over 3 load times (peak, shoulder, and valley hours) across 4 seasons.

After the PROMOD IV® simulation is done, the resulting binding constraints are checked for validity and accuracy and edited or removed from the EVENT file as necessary. For the 2009 Planning Year study, the EVENT file data was reviewed and the resulting feedback from Midwest ISO stakeholders (rating updates, remove/add events) was implemented as necessary.

2.1.5. Pool Definition

A pool is an area composed of a set of companies inside which all generators are dispatched together to meet the total pool load. Normally pools represent an energy market, like MISO or PJM. The study footprint was broken into several pools based on the structure of the energy market. In the MTEP 09 PROMOD IV® case, 11 pools were defined in the study footprint: MISO, PJM, SPP, MAPP, SERC, TVA, MHEB, NYISO, ISONE, IESO and Eastern Canada. Figure 2.1.5-1 shows all pools modeled in the study footprint.

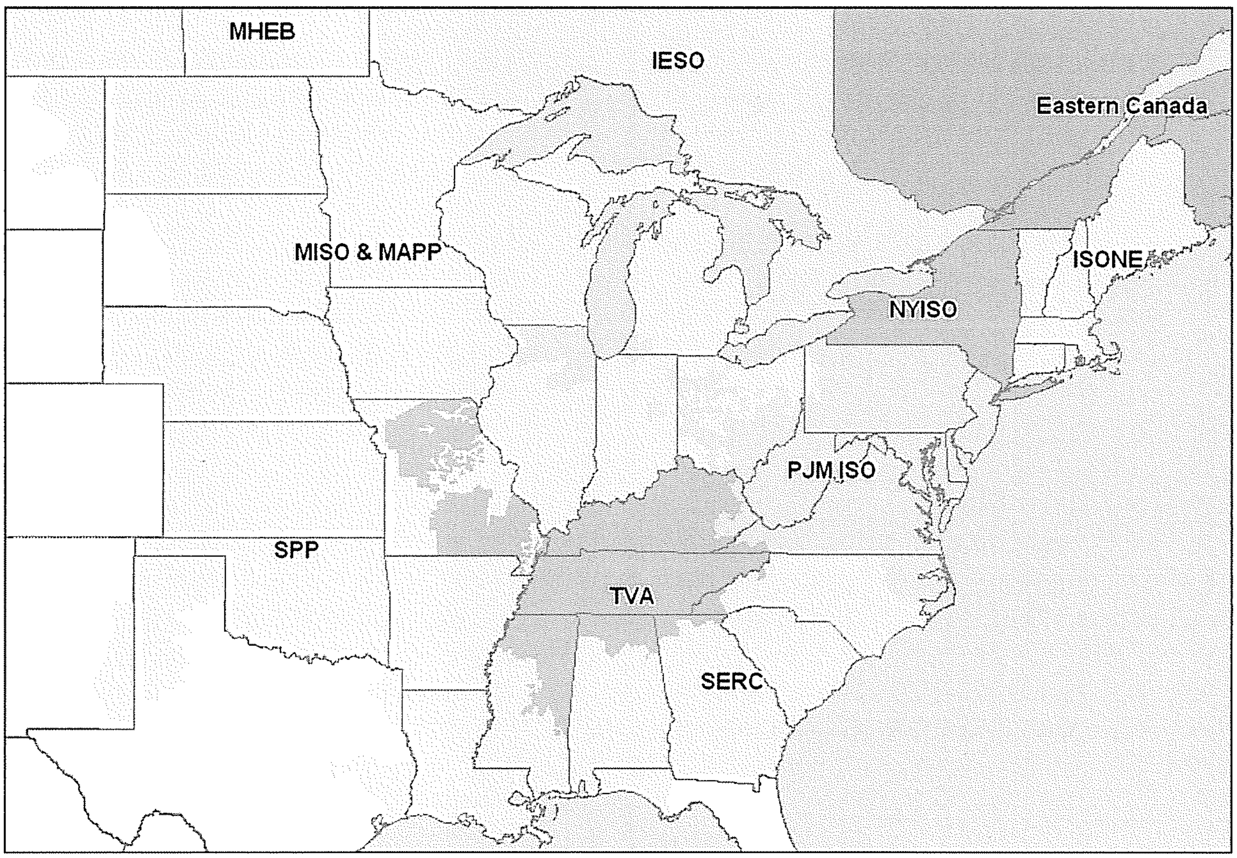


Figure 2.1.5-1: Pools in PROMOD IV Case

2.1.6. Hurdle Rates

Hurdle rates influence the capability of a pool to obtain support or sell energy to other pools. If two pools want to exchange energy, the difference of dispatch costs between the buying pool and selling pool must be greater than the hurdle rate between them.

PROMOD IV® performs the security constrained unit commitment and economic dispatch. Its solution includes two steps. The first step is unit commitment, and the second step is economic dispatch. For each step, the user can define its own hurdle rate. The hurdle rate defined for the unit commitment step is called the commitment hurdle rate, and the hurdle rate defined for the economic dispatch step is called the dispatch hurdle rate.

Normally, users will set the commitment hurdle rate to be more expensive than the dispatch hurdle rate such that the pool units will be dispatched against the pool load first in order to get the commitment order right and then allow pool interchange during the final dispatch via the dispatch hurdle rate.

There is no standard way to define the hurdle rates. Normally, hurdle rates are determined based on the filed transmission through-and-out rates, plus a market inefficiency adder.

In this study, the commitment hurdle rates are set at 10 $/MWH between all pools. The exception was MISO to MH, where we set the commitment hurdle rate set at 0 $/MWH. While MH is not a Midwest ISO Transmission Owner, an agreement between MH and the Midwest ISO, is more appropriately represented with a zero hurtle rate versus other entities outside the Midwest ISO. The dispatch hurdle rates between pools are shown in
Table 1.

Table 1: Hurdle Rates

	Dispatch Hurdle Rate ($/MWH) Peak/Off-Peak										
To->	PJM	MISO	TVA	MAPP	SPP	SERC	E-CAN	IMO	ISONE	MHEB	NYISO
From											
PJM	*	2.5/2.5	4.8/4.8	4.8/4.8	N/A	4.8/4.8	N/A	N/A	N/A	N/A	7/7
MISO	2.5/2.5	*	7.6/5.4	7.6/5.4	7.6/5.4	7.6/5.4	N/A	7.6/5.4	N/A	0/0	N/A
TVA	6.5/4.5	8.3/8.3	*	N/A	8.3/8.3	8.4/5.7	N/A	N/A	N/A	N/A	N/A
MAPP	4.3/3.7	4.3/3.7	N/A	*	N/A	N/A	N/A	N/A	N/A	6.5/4.5	N/A
SPP	N/A	5.1/5.1	5.1/5.1	5.1/5.1	*	5.1/5.1	N/A	N/A	N/A	N/A	N/A
SERC	6.5/4.5	8.3/8.3	6.8/5.0	N/A	8.3/8.3	*	N/A	N/A	N/A	N/A	N/A
E-CAN	N/A	N/A	N/A	N/A	N/A	N/A	*	N/A	5/5	N/A	5/5
IMO	N/A	10.5/8.5	N/A	N/A	N/A	N/A	N/A	*	N/A	10.5/8.5	6.5/4.5
ISONE	N/A	N/A	N/A	N/A	N/A	N/A	5/5	N/A	*	N/A	5/5
MHEB	N/A	0/0	N/A	11.6/7.3	N/A	N/A	N/A	11.4/7.1	N/A	*	N/A
NYISO	5/5	N/A	N/A	N/A	N/A	N/A	5/5	7/5	5/5	N/A	*

2.1.7. Losses

Load in PROMOD IV® is equivalent to the actual load plus losses as determined by the model in one of three fashions. In the option chosen for this study losses were represented by a loss component within the Locational Marginal Prices (LMPs). The other options for analysis were to assume losses were included in the load or to calculate losses based on a dynamic iteration that would have increased runtimes three fold and is only used in studies where an extremely accurate loss calculation is needed.

2.1.8. Monte Carlo Outage and Auto Maintenance

For the 2009 Planning Year Study, the outage library that was created for PROMOD IV® ignored forced outages due to GE-MARS capturing the generator forced outage aspect in the LOLE portion of the study.

PROMOD IV® generates a maintenance schedule which optimizes maintenance to minimize loss of load events. After a maintenance schedule is developed, the same schedule is maintained for all subsequent PROMOD IV® simulations.

2.2. Analysis of System

A security constrained economic dispatch (SCED) simulation was run yielding Locational Marginal Prices (LMPs) for the various load buses which were representative of the cost for energy throughout the simulated period. These LMP values contain a component representative of the cost of congestion to that bus known as Marginal Congestion Cost (MCC). These MCC values can either be positive or negative to indicate if there is a shortage or surplus of generation. Trapped generation around a bus is indicated by negative MCC values and a scarcity of generation around a bus is represented by positive MCC values. The MCC metric is available in PROMOD IV® for all modeled buses. Given that there was a plethora of buses modeled within the PROMOD IV® analysis it was imperative that selection criteria be utilized to narrow down the results. This study examined the most positive and most negative MCC values present on the system during peak conditions. These positive and negative MCC values were then grouped with surrounding buses of similar values to form the zones to be utilized in the LOLE study. This bus-based information affords the ability to quantify the load and generation in each zone, as needed in the GE MARS application going forward.

2.2.1. Selection of Buses for Contour Maps

PROMOD IV® can calculate hourly LMP components for selected buses. However, it is not feasible to analyze this data for all buses in the system. This would result in approximately 400 million (8,760 hours x 50,000 buses) Marginal Congestion Component (MCC) values. Therefore, a smaller selection of buses from hourly output was utilized for analysis and contour map definition. The respective coutour maps for 2009 and 2018, are shown on Figure 4.2.1-1 and Figure 5.1.2-1.

The buses were selected by multiple but not absolute criteria. For a bus to be selected, it was first required that a latitude and longitude was available for plotting purposes. Buses that were listed in monitored lines within the event file were selected. The event file buses were plotted and it was found that some geographic areas would not have enough data points for contouring purposes necessitating the selection of additional buses at various voltage levels. Higher voltage buses were preferred over lower voltage buses. Buses were added until there were a sufficient number of points for contouring over the study footprint. For the 2009 Planning Year Study, 1,410 buses were selected.

2.2.2. Zonal Filtering Criteria

At this stage of the study, candidate zones are evaluated to determine if they contained either 2000 MW of load or 2000 MW of generation. If a candidate zone did not meet the 2000 MW threshold, it was merged into the appropriate adjacent zone. A breakdown of the zones established through this process can be seen in Figure 2.2 2009 GE MARS Modeled Zones. The precursor geographically output information utilized to draw the refined_ Figure 2.2 2009 GE MARS Modeled Zones is shown on Figure 4.2.1-1 in the Section 4.2.1 Congestion Impact. Guidelines for merging smaller sized different colored areas into a larger composite area are set out in the Tariff and Business Practice documents. Regarding the larger zones, Zone 4 emerged as a different type zone through the technical analysis. No division between Zones 6 and 7 was warranted based on the congestion findings. However per FERC directive for the 2009 PY, a division between Zones 6 and 7 was sustained in the process in order to retain the geographic identity of the standing Midwest ISO Transmission Expansion Plan (MTEP) planning areas in Attachment FF-3 to the Tariff.

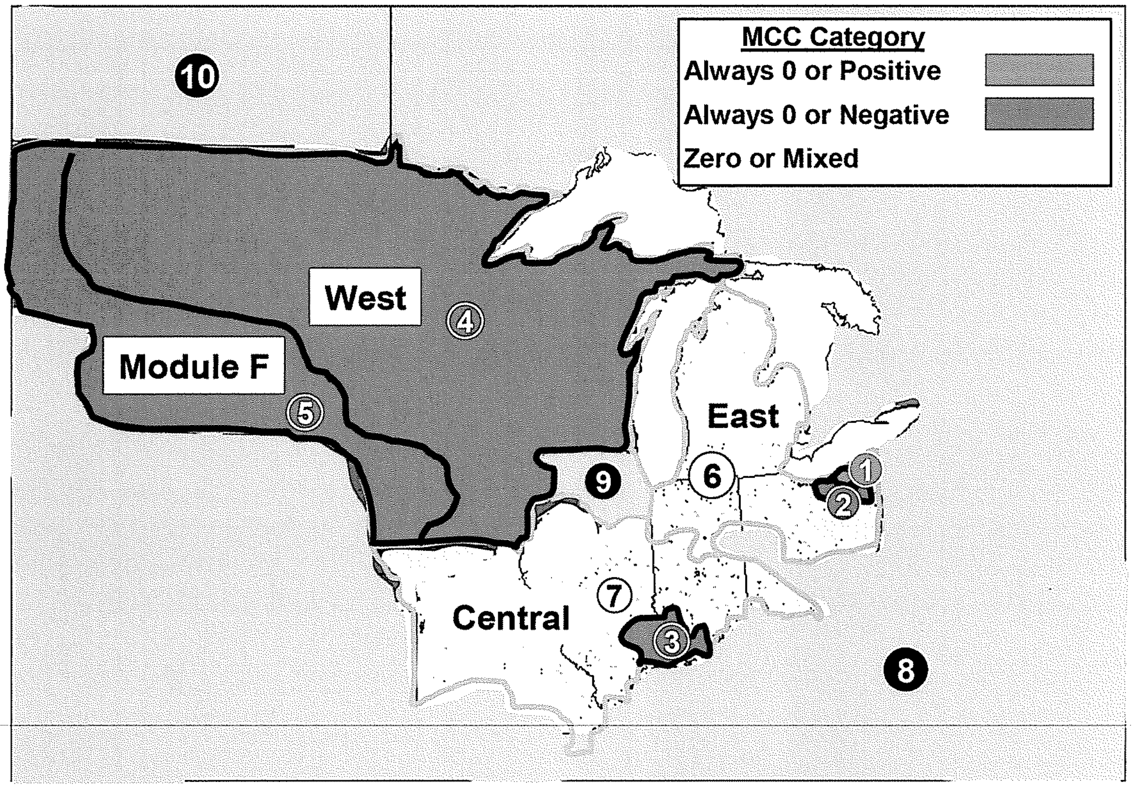


Figure 2.2 2009 GE MARS Modeled Zones

2.2.3. Transfer Analysis

The common red or blue clusters viewed in Figure 4.2.1-1 for the year 2009, and Figure 5.1.2-1 for the year 2018 are precursors to candidate zones. After same sign (same color) clusters were evaluated or merged into final zones as in Figure 2.2 2009 GE MARS Modeled Zones, PROMOD IV® was used to determine the transfer limits between zones. The prices of generation in each zone were artificially adjusted to encourage power imports into generation deficient zones (red as seen in Figure 2.2 2009 GE MARS Modeled Zones) and exports from generation rich zones (blue as seen in Figure 2.2 2009 GE MARS Modeled Zones). This was done by setting the price of generation to be high in generation deficient zones, and the price of generation to be low in generation rich zones. The hourly zone interfaces flows were then evaluated to determine monthly limits for input into GE-MARS. The monthly limit was equal to the average of the interface flows at time of daily peak. For example, the January limit was the average of 31 flows at daily peak values.

2.2.4 Load Deliverability Analysis

After the zones are identified and the transfers are established between those zones an analysis must be performed to determine if the import limited zones (red zones in Figure 2.2 2009 GE MARS Modeled Zones and Figure 2.2.4-1 in Section 3.1) have enough combination of resources and import capability to maintain an LOLE of 1 day in 10 years. If these zones do have enough Effective

Import Transmission Capability (EITC) to maintain 1 day in 10 years then they are set at the same level of reliability as the rest of the system and can share the same Planning Reserve Margin without the need for additional short term precautions being taken. This testing of the red (i.e. positive MCC) zones is accomplished at the lavender diamond shaped activity shown on the right side of the Process Map in Section 2.2.4.

For the 2009/10 Planning Year only one zone was found to be import constrained (zone 1 in Figure 2.2 2009 GE MARS Modeled Zones) and required a load deliverability analysis to be performed. Along with the resources internal to Zone 1, the 3,311 MW level of EITC was found to be sufficient import capability to maintain 1 day in 10 years LOLE and therefore no additional precautions were recommended for Zone 1 at this time.

2.2.4. Process Map

The process map below illustrates the LOLE study data flow.

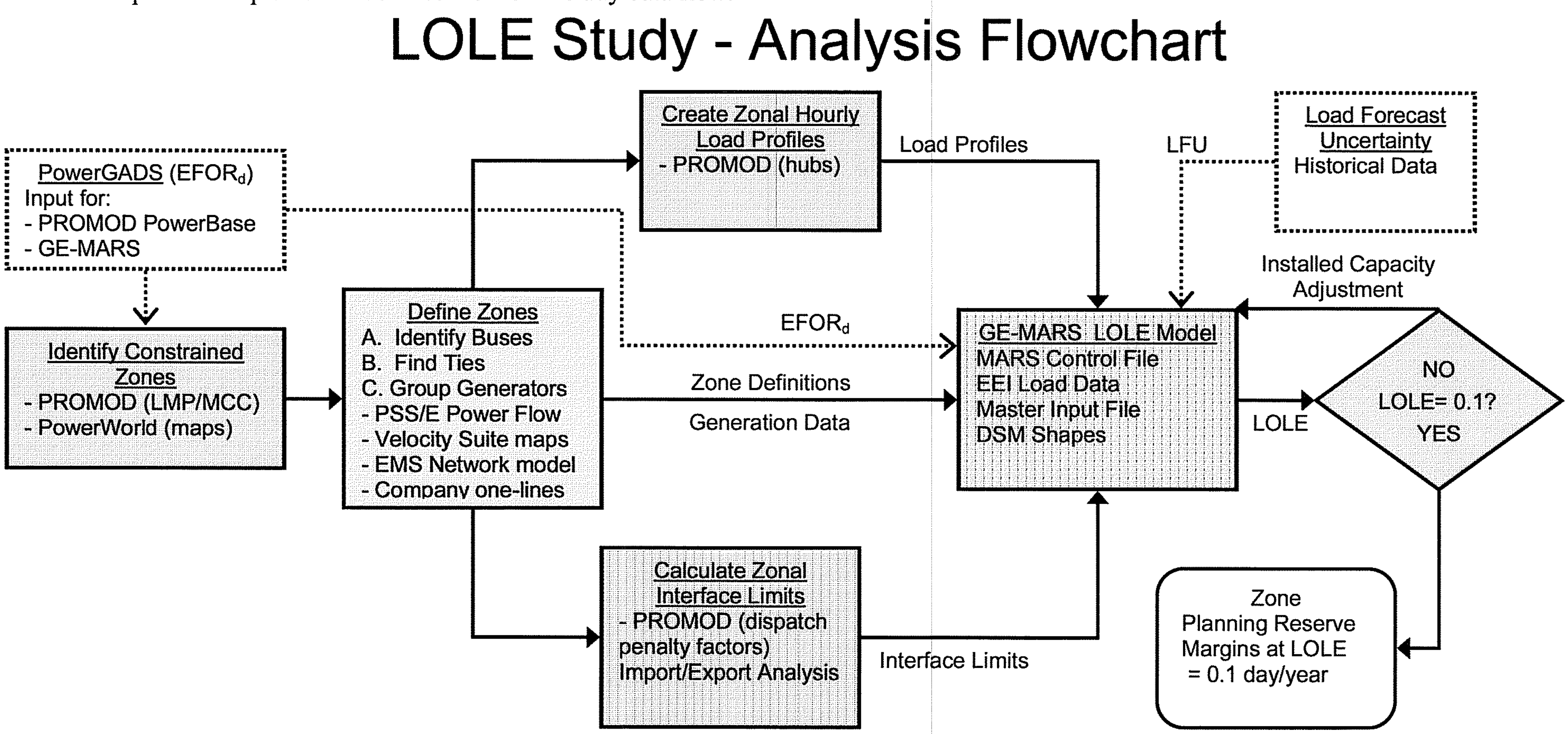


Figure 2.3: LOLE Study Analysis Flowchart

3. GE MARS Analysis

Utilizing the zones derived from the PROMOD IV® analysis, a MARS model was constructed using load, transmission and generation data from PROMOD IV® PowerBase and incorporated unit outage statistics derived from Generating Availability Data System (GADS) reporting through the Midwest ISO's PowerGADS software. The blue box on the process map in Section 2.2.4 indicates the GE MARS activity.

3.1. Construction of GE MARS Model

The PROMOD IV® tool was used to group the buses as specified in Section 2 and output the load profiles for each zone. These load profiles and zonal definitions were placed in the MARS Model where the transfer limits, also determined from the PROMOD IV® analysis, were applied. The generating units for each zone were also imported from the PROMOD IV® model; however, Forced Outage Rates (FOR) were updated with the recently available GADS data. The inputs garnered from the PROMOD IV® analysis are represented in Figure 2.2.4-1 as they were input to the GE MARS model.

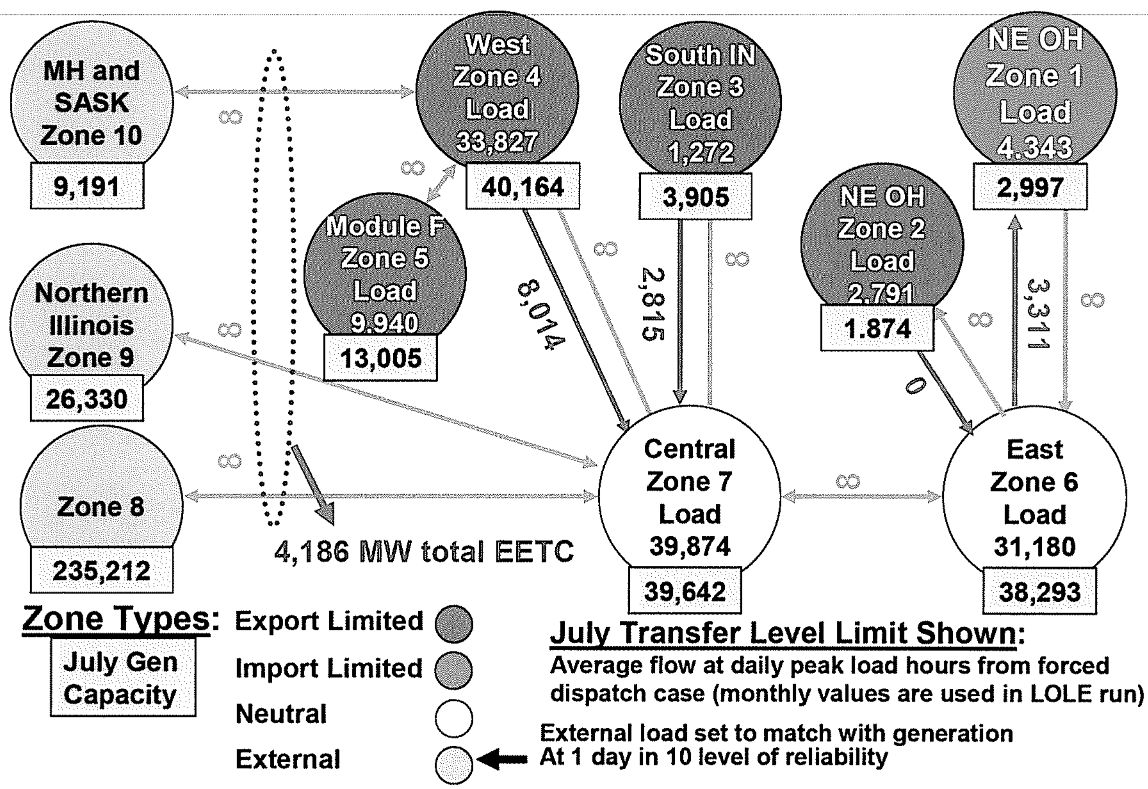


Figure 2.2.4-1: Zones and Parameters Modeled in 2009 GE MARS

3.1.1. Modeled External System Ties

In order to determine an appropriate level of support the external systems were held to the same reliability level as the internal system and an external tie capacity was derived. Historical total transmission flows and contractual flows were observed to obtain an applicable external support level. The 4,186 MW value for the external Effective Import Tie Capability (EITC) is shown in Figure 2.2.4-1. This value was determined as follows:

Table 2: External EITC Calculations

Maximum transmission import flow from Market Externals 8/1/2006	=	10,477 MW
Less transmission capability needed to serve 2007 Summer firm deliveries into Market	=	6,291 MW
Available transmission to import into Market	=	4,186 MW

3.1.2. Migration of GADS data into Study Model

The Generating Availability Data System (GADS) provides a standardized means to collect outage information on generators. This system was used to collect data for units within the Loss of Load Expectation study for the period of July 2005 through June 2008. This historical data was then used to calculate Forced Outage Rates (FOR) for each unit within the footprint that were then imported to the GE MARS model. If a given unit did not have outage statistics, an average outage rate for that type of unit was applied for use in the study. These class average forced outage rates were derived from the Midwest ISO GADS system where possible and from NERC data when the Midwest ISO data did not contain enough units to provided a statistically significant class average. The class averages utilized in the Midwest ISO area and their sources for this study are listed in Table 3.

Table 3: Class Average EFORd

EFORd Units Class	Pooled EFORd (%)	Data Source
Combined Cycle	5.933	MISO
Combustion Turbine (1-19 MW)	16.644	MISO
Combustion Turbine (20-49 MW)	11.665	MISO
Combustion Turbine (50+ MW)	7.356	MISO
Diesel Engines	9.374	MISO
Fluidized Bed Combustion	6.780	NERC
HYDRO (1-29 MW)	4.062	MISO
HYDRO (30+ MW)	3.080	NERC
Nuclear	3.940	NERC
Pumped Storage	2.570	NERC
Steam - Coal (1-99 MW)	6.587	MISO
Steam - Coal (100-199 MW)	6.501	MISO
Steam - Coal (200-399 MW)	8.301	MISO
Steam - Coal (400-599 MW)	8.031	MISO
Steam - Coal (600-799 MW)	6.242	MISO
Steam - Coal (800-999 MW)	3.540	NERC
Steam - Coal (1,000+ MW)	8.630	NERC
Steam - Gas	6.460	NERC
Steam - Oil	12.190	NERC
Steam - Waste Heat	6.780	NERC

Forced outage rates utilized in this study were adjusted to exclude certain outage types, deemed as outside of management control, and account for the time when a unit was in demand as outlined in Appendix C EFORd, XEFORd, UCAP Metrics. These adjustments to the forced outage rates yielded an Effective Forced Outage Rate Demand (EFORd) that excluded certain outages which were outside of the generation managements control otherwise known as XEFORd. While the EFORd values were utilized in the MARS simulations in order to capture all possible outages of generation the XEFORd values were utilized in Planning Reserve Margin calculations after the simulation was run as seen in Section 3.2.

Generator Forced Outage Rate definitions:

- **Equivalent Forced Outage Rate Demand (EFORd)**: A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
- **XEFORd**: Same meaning as EFORd, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example loss of transmission outlet lines are considered as OMC relative to a units operation.

The OMC codes excluded by the Midwest ISO are itemized in Appendix C.

3.1.3. Load Forecast Uncertainty (LFU)

At the recommendation of the LFU Task Team this study utilized the NERC Bandwidths Variance Calculation in order to determine a Load Forecast Uncertainty value. This method was recommended based on its historical use and its vetting through various groups.

The majority of analysis performed by the task team converged on a similar number in the 4.00% standard deviation range. Using the NERC Bandwidths Variance Calculation a sigma value of 4.04% for the summer and 4.08% in the winter was determined. This load forecast uncertainty was applied to the entire footprint and more information (including the LFU values used as input to the MARS model) on LFU can be found in Appendix B Load Forecast Uncertainty (LFU) Final Report.

3.2. Determination of Planning Reserve Margin

Once the base model with generation, load, and tie line capabilities was defined, a simulation was run to determine the Loss of Load Expectation (LOLE) value for the planning year. Capacity adjustments were then put in place to alter the available capacity to each zone to ensure that the Midwest ISO system as a whole attained a LOLE value of 1 day in 10 years or 0.1 days/year. And if the Midwest ISO system as a whole is at the targeted value of 0.1 days/year then consequently any sub part of that system (like the congestion-based LOLE modeled zones) would have a LOLE of 0.1 days/year or less like the congestion based LOLE zones. Concurrently, all external zones were modeled at the same level of reliability to ensure that they were not providing more support than would be statistically available. When capacity was appropriately adjusted in each LOLE zone to bring all systems to a 0.1 days/year LOLE value the ratio of capacity to coincident load in the Midwest ISO yielded a reserve margin of 15.4%. This value is the planning reserve margin as applied to the Midwest ISO system coincident peak. For Planning Year 2009/10 the same Planning Reserve margin will be applied to all three planning areas (East, West and Central) as defined in Attachment FF of the Tariff for compliance with Module E.

In order to account for the diversity within the system and yield a reserve margin applicable to individual Load Serving Entity (LSE) monthly peaks, as mandated by Module E, a diversity factor was necessary to more accurately reflect the requirements of the system as determined in the LOLE study model. The Midwest ISO calculated historical annual diversity factors for 2005 through 2008 by comparing the Midwest ISO system peak to the sum of the Local Balancing Authority Peaks for each year. Because Loadzone CPNode configurations can and often do change on a quarterly basis it was necessary to use the LBA peaks in order to get a meaningful comparison of diversity factors from one year to another. Below is the calculation and resulting diversity factors for 2005 through 2008.

$$Diversity\ Factor = 1 - \frac{MISO\ Coincident\ Peak}{\sum^{Year} MISO\ BA\ Peak}$$

Year	Diversity Factor
2005	3.84%
2006	2.35%
2007	5.66%
2008	5.78%

The amount of diversity experienced in the Midwest ISO footprint since the start of the Energy Market in 2005 has ranged from 2.35% at its lowest in 2006 to a high of 5.78% in 2008. Because of the limited amount of historical data available to the Midwest ISO and the significant impact diversity factor would have on the resulting Planning Reserve Margin the Midwest ISO sought feedback from stakeholders on how much diversity should be considered. Although stakeholder opinions varied the significant majority supported using a diversity factor on the lower end of the historical range. Based on that feedback the Midwest ISO decided to use a diversity factor of 2.35% for the 2009/10 Planning Year. This value was applied to the coincident load used in the original reserve margin calculation to yield a non-coincident peak load from the system coincident peak. This increased load value was utilized to yield a 12.69% planning reserve margin as applied to individual LSE peaks.

The final step was determination of the planning reserve margin on an unforced capacity basis. The system wide average for XEFORd values for generation within the Midwest ISO Market was 6.514%. This was developed by applying an actual collected value of XEFORd of 6.75%, computed from the history log for generators that represented 83.5% of the MW Modeled in the GE MARS simulation. The 6.75% was applied to all 130,446 MW of Generation in Model. A 0.00% XEFORd was applied to 4,717 MW of Demand Resources in Model. By combining the two on a MW weighted bases, a System Wide Average XEFORd = 6.514% was calculated for use in a Unforced Capacity Reserve Margin. This outage rate was then applied to the capacity in the previous reserve margin ratios. This lower capacity value was then divided by the previously adjusted load value to arrive at a new planning reserve margin of 5.35% which must be served with unforced capacity. Unforced capacity for an individual unit is derived by applying a unit's XEFORd to its maximum capacity rating to arrive at a reliably provided MW value.

3.3. Example of Applying the Results

Table 4 utilizes the load values from zones 1, 2, 3, 4, 6 and 7 shown in Figure 2.2.4-1 within the GE MARS model and quantifies the various values relative to the resulting PRM's, coincident and non-coincident peak load, diversity, and the XEFORd forced outage rate. The usage of IGEN, UCAP, XEFORd, etc. are exemplified in Appendix C EFORd, XEFORd, UCAP Metrics, and OMC Codes.

Table 4: For the Midwest ISO Market Planning Reserve Zones at 2.35% peak load diversity, XEFORd=6.514% and 15.40% $PRM_{SYSIGEN}$

	Non-coincident Load Based		Coincident Load Based
Generator MW Basis:	**UCAP**	**IGEN**	**IGEN**
Total PRM (first column is applicable to Forecast LSE Requirement)	**5.35%**	**12.69%**	**15.40%**
Midwest ISO Market Zones Load	**113,287**	**113,287**	**110,625**
Midwest ISO Market Zones Required Capacity	**119,345 $_{UCAP}$**	**127,661 $_{IGEN}$**	**127,661 $_{IGEN}$**

4. Details of 2009 Results

4.1. Further Discussion of Findings

4.1.1. Monthly Distribution of Loss of Load Expectation

The accumulation of the LOLE throughout the 2009 planning year reveals that 98% of the accrued annual LOLE is realized in the month of July with 1% accumulation in both June and August. Figure 4.1.1-1 illustrates the distribution.

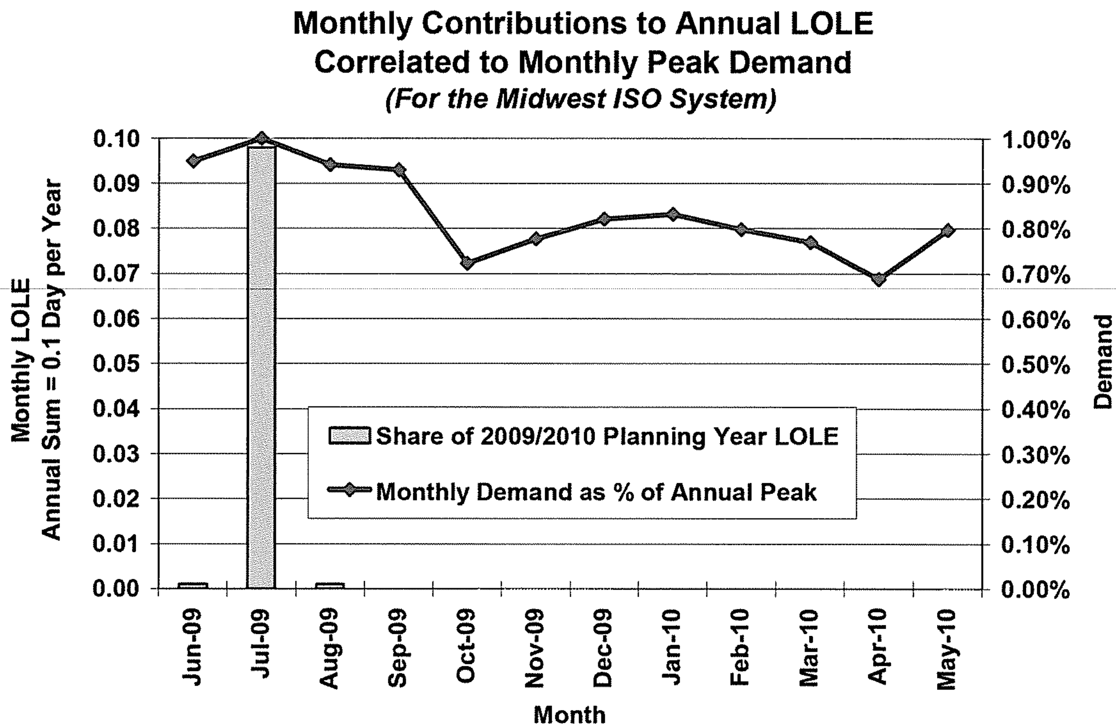


Figure 4.1.1-1 Monthly Distribution of Annual LOLE

4.1.2. Unforced Capacity (UCAP) Metric Review

The table in Section 0 laid out the applicable Resource Adequacy Requirements (RAR) for the 2009 Planning Year; 15.40% $PRM_{SYSIGEN}$, 12.69% $PRM_{LSEIGEN}$, and 5.35% PRM_{UCAP}. The relationship and calculation among these values for a solved LOLE case, and how they relate to the system wide average XEFORd is explained by example in Appendix C EFORd, XEFORd, UCAP Metrics.

The metric of Unforced Capacity (UCAP) was utilized in this years study in order to more equitably distribute the reserve requirement amongst a fleet of generation with varying outage rates. Through the use of Unforced Capacity all entities will utilize equivalent capacity to serve reserve margins.

4.2. Sensitivity Analysis and Unbundled Components

Prior to the 2009 study, some general sensitivity work was done on sample data sets. These studies concluded that the major factor driving PRM results is the forced outage rate of generators. With the more quantitative and specific data available in the actual 2009 study, certain sensitivity work was performed to better understand the influence of various factors. One basis, like XEFORd-based results for example, is required to be quantified in the Tariff, while RE standards relate EFORd-based results. The interest in sensitivity was two-fold, 1) to find out the significant drivers in view of the specific data for the Midwest ISO, and 2) to relate the volatility of certain components that are utilized in Module E of the Midwest ISO Tariff. Results of the sensitivity aspects are discussed further in this section, and Table 5 is a summary of the sensitivity effort.

Examples that drive interest for and relate to the added value realized from the sensitivity analysis are as follows:

- Installed Capacity- On the surface, the RE standards are geared for a basic PRM based on installed capacity.
- Transmission Limitations- The RE standards also require in **R1.3.3** that "Transmission limitations that prevent the delivery of generation reserves" be accommodated in the study, and this drives interest in knowing the PRM without transmission limitations versus the PRM with transmission limitations. The Midwest ISO study process is designed to allow quantification (in terms of the PRM) of the deliverability impacts due to transmission limitations.
- Congestion- The Tariff is unique in that the fundamental driver for modeling zones is transmission congestion-based. In addition, tracking and quantifying the construct is good practice, and helps communicate the effort. The increased impact to PRM from 0.61.% in 2009 to 2.3% in 2018, is an important finding. Unaddressed, this would represent significant additional investment in resources. This finding will be introduced to the MTEP process for review of potential transmission expansions that could mitigate the increase indicated for 2018, or seek to decrease the congestion impact from the 0.61% level realized in 2009. The Tariff mandates directing congestion impact to the MTEP process for solutions, when the congestion affects deliverability to load causing a greater than 1 day in 10 out come in a future year of the LOLE study.
- EFORd vs. XEFORd- The Tariff measures LSE compliance to cover its load plus PRM in terms of generators UCAP ratings. It is of interest therefore that sensitivity runs are done to differentiate the total EFORd impact needed for RE compliance of the system, from the segregated XEFORd compliance basis used for setting the UCAP ratings of LSE's resources within the Tariff. The difference between EFORd and XEFORd

is that the OMC component of EFORd is excluded. This exclusion defines the XEFORd basis, and results in a different PRM metric.
- External Tie Capability- The Midwest ISO chose to demonstrate sensitivities to the external tie capability.

The general approach to determining the effect or response to a particular sensitivity component was to run selected GE MARS runs with differing inputs. The cases were structured such that a comparison between the proper two cases would reflect the quantifiable impact of a particular component. For example, while the key output from an LOLE model is the PRM_{IGEN} based on the Installed Generation Capacity (IGEN) the tariff utilizes UCAP-based generator ratings. For the Tariff, a lower numerical PRM is determined based on the also lower equivalent Unforced Capacity (UCAP) MW rating basis. Table 5 is a "cross word puzzle" approach to summarizing the output from the selected LOLE cases directly while at the same time illustrating the cumulative and incremental impact of the LOLE metrics reflected by variations in:

- Input data such as XEFORd versus EFORd for example
- Quantify PRM_{UCAP} for specified LSE Load Diversity level, from the core GE MARS PRM_{IGEN} results.

All column headings in Table 5 with the "UCAP" parameter, reflect results for UCAP MW's (i.e. equivalant capacity that would have XEFORd = 0).

The selected components are called out in column 15 in Table 5. The relative stand alone or incremental impact of a component is quantified in the columns 12 through 14. Together, the highest two impacting components in column 14, the 8.49% impact of generators' XEFORd outage rate and the 6.89% impact of Load Forecast Uncertainty (LFU), account for 15.37% of the total 15.40% PRM_{IGEN}.

The differences among rows are related to the sensitivity component in column 15, and the differences across the column set 9, 10 ,11 and the column set 12, 13, 14 ; are due to a different metric of PRM from the Tariff being expressed. Similarly, columns 9, 10, and 11 are the cumulative effect of accounting for each component listed in column 15, and columns 12, 13, and 14 display the incremental impact to the total PRMs. The values for the incremental sensitivity components of columns 12 through 14 total to the values indicated by blue font in Table 5. Column 1 states an abbreviated title for each MARS case and columns 2 through 8 specify the make up of the LOLE case's construction (i.e. indicating which component or components are active or not in the particular GE MARS run). Column 11 shows the PRM on and Installed Generation Capacity basis. Column 11 values with red or blue font indicate a value obtained directly from the particular simulation case. For the top three rows; the top row (of zeros) was set by definition, the second row is derived from the -0.79% difference in column 14, and row 3 is driven by the 2.35% load diversity parameter (outside of a GE MARS run).

Table 5: Results Summary, Cumulative Impact of LOLE Driving Components and Incremental Change Due to Each

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
								Cumulative Sum			Incremental Change			
								Non-coincident Load Based		Coincident Load Based	Non-coincident Load Based		Coincident Load Based	
Senario Title	Load Diversity	Load Uncertainty	XEFORd Generation	EFORd Generation	Congestion	With Op. Reserve	With External Tie	PRM_{UCAP}	$PRM_{LSEIGEN}$	$PRM_{SYSIGEN}$	PRM_{UCAP}	$PRM_{LSEIGEN}$	$PRM_{SYSIGEN}$	Incremental Component
Certain Load and EFORd = 0								0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	None
External Tie							X	-0.72%	-0.77%	-0.79%	-0.72%	-0.77%	-0.79%	External Tie
Account for 2.35% Load Diversity	X						X	-3.07%	-3.12%	-0.79%	-2.35%	-2.35%	0.00%	Diversity
Load Uncertainty	X	X					X	3.61%	3.61%	6.10%	6.68%	6.73%	6.89%	LFU
No congestion reference XEFORd Generation and BTM @2.35 Diversity	X	X	X				X	4.61%	11.90%	14.59%	1.00%	8.29%	8.49%	XEFORd
With congestion XEFORd Generation and BTM @2.35 Diversity	X	X	X		X		X	5.16%	12.49%	15.20%	0.56%	0.60%	0.61%	Congestion
With congestion EFORd Generation and BTM @2.35 Diversity	X	X		X	X		X	5.35%	12.69%	15.40%	0.18%	0.20%	0.20%	Force Majeure (OMC codes)
								Sum of Incremental Values			5.35%	12.69%	15.40%	

Additional Sensitivity Case

No External Tie	X	X		X	X			6.07%	13.46%	16.19%

Notes: - Key results applicable to 2009 RAR are indicated with blue font, GE MARS PRM_{IGEN} run results or values by definition are in red font, all other values are calculated per the Module E relationships demonstrated in Appendix B or calculated from incremental differences between GE MARS runs. The 2.35% Load Diversity impact is an adjustment that does not require a GE MARS run. The 0.79% value for the External Tie is equal to the difference between the column 11 values for two cases **[(16.19% - 15.40%)** = 0.79%]

The following list provides a brief description of each incremental component in column 15 of **Table 5**, and its value in column 14. By definition the first row of values in **Table 5** has zeros because there is no impact to needing additional reserve generation MW (i.e. PRM=zero) above a load forecast that is 100% certain. The foot-note in Table 5 helps distinguish which values were calculated in a GE MARS run versus the UCAP ratings of generators and the 2.35% diversity applied to LSE loads under the Tariff:

- External Tie - The 4,186 MW value for external Effective Import Tie Capability (EITC) is shown in Figure 2.2.4-1, and it's development was shown in Table 2. The incremental impact on PRM is calculated by entering a zero EETC value in the model versus the 4,186 MW value. The difference in PRM's between the two runs is 0.79%. Relative to the first line in Table 5, adding the benefit of the tie would allows the PRM to be 0.79% less.
- Diversity – The GE MARS finds the coincident peak among the various peaks for the zones modeled. However, for compliance in the Tariff, individual Load Serving Entities (LSEs) maintain reserves based on their monthly peak load forecasts. These LSE peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 2.35 % diversity factor among LSEs as described in section 3.2.
- LFU – The Load Forecast Uncertainty (LFU) is discussed in Appendix B. For 2009 a constant 4.04% Summer LFU was applied in the runs. Sensitivity runs with the 4.04% LFU versus zero LFU, impacted the $PRM_{SYSIGEN}$ value by 6.89%, as indicated in Table 5..
- XEFORd - The impact of generator forced outages without the Outside Management Control (OMC) cause category of outages is 8.49% as shown in Table 5.
- Congestion - The 0.61% PRM_{IGEN}, and the 0.56% PRM_{UCAP} values due to transmission Congestion (see Table 5) are a means to quantify the amount of additional aggregate generation MW needed to overcome the effect of aggregate un-deliverability. This represents a statistical amount of generation capacity that is not able to serve load, and therefore is an amount that is added to the requirement for capacity overall to sustain the overall system at the 0.1 day per year LOLE standard. The 0.61% PRM_{IGEN} value multiplied by the forecasted 110,625 MW coincident 2009 peak (from Table in Section 0) is equivalent to needing 675 MW of additional generation to overcome the effect of congestion. The 675 MW of generation would be a typical generator with an XEFORd equal to the system wide average XEFORd = 6.514%. In terms of UCAP capacity, 643 MW would be needed to compensate for congestion determined by the 0.56% PRM_{UCAP} times 113,287 MW (from Table 4 in Section 0). The 675 MW amount of additional generation is revealed by the difference in the amount of capacity resources

needed in a simulation to meet the 1 day in 10 criteria with the internal market transmission tie values in Figure 3.1 imposed, versus a simulation that ignores those internal limits. The affected tie limits are those from zones 1, 2, 3, and 4 to zones 6 and 7. Table 6 is intended to clarify how deliverability is addressed and applied by the Midwest ISO in accordance with the Tariff. Central to the Tariff and the process is that the zones are developed on a congestion basis (i.e., quantifiable EETC or EITC values), and because of this the impact of congestion is quantifiable in terms of a slice of the reserve margin required. The following points track the connection between congestion metrics from the sign of the MCC in $/MWH in the zone formation, to a quantifiable MW amount of transmission tie capability or generator MW capacity..

- The formation of the zones depicted in Figure 2.2 are driven by the behavior of the sign of the MCC metric indicated in the last row of Table 6.
- Depending on the direction (into positive-signed MCC zones, or out of negative-signed MCC zones) the MW limiting value for the ties to the zones in Figure 3.1 are set by the metric EITC (into a +MCC zone) or EETC (out of a –MCC zone), terms also indicated in the last row of Table 6.

- Definitions from the Tariff:

  - 1.75f Effective Import Tie Capability (EITC): The maximum aggregate level of power in MW that can be reasonably expected to flow on the transmission tie lines into a specified zone of the Transmission System, while maintaining reliable operation.
  - 1.75g Effective Export Tie Capability (EETC): The maximum aggregate level of power in MW that can be reasonably expected to flow outward on the transmission tie lines of a specified zone of the Transmission System, while maintaining reliable operation.

- Force Majeure (OMC codes) - Table 5 also shows the impact of the EFORd outage rate which includes the XEFORd outages and the impact of OMC type outages. The additional 0.20% due to the OMC is shown as the last row in the top portion of Table 5. The list of the NERC codes selected as OMC codes by the Midwest ISO is in Appendix C.

Table 6: Reference to Deliverability Definitions from FERC Tariff

Defined Tariff Term	Defined At	Tariff Area and Driver	Milestone Index or Report
Market Transition Delivery Test	1.188c	Module E one time pre-market event. Some only have Energy Resource Interconnection Service beyond the local area	Amount eligible for both Network Resource Interconnection Service and amount retained as limited Network Resource Designation to single local load balancing area, and may request full aggregate deliverability under Attachment X
System Impact Study	1.297	Module E 69.2.1.4 Connection Study	Network Resource Interconnection Service granted
Firm Designation of a Resource as a Network Resource under Network Integration Transmission Service	1.212	OASIS request for drive-In, and drive-Within service for firm bilateral transactions	Period specific Firm Transmission Service
Firm Point-To-Point Transmission Service	1.102	OASIS for In, Within, Out, and Through, for firm bilateral transactions	Period specific Firm Transmission Service
Marginal Congestion Component (MCC) Effective Import Tie Capability (EITC) Effective Export Tie Capability (EETC)	1.177 1.75f 1.75g	Module E 68.1.1 LOLE Study based on congested zones identified by the sign of MCC $/MWH metric over a period of time in the network, and where the effectiveness of delivering aggregate generation to load is limited by the directional MW ratings of modeled transmission ties. Both the defined zones and the ratings of the ties are accounted for in setting the Planning Reserve Requirement	Annual LOLE study to determine the PRM. PRM compliance results for current Planning Year, and study results for 9 subsequent years

4.2.1. Congestion Impact

Congestion incorporates the notion of aggregate deliverability impact between zones in GE-MARS, and a quantifiable MW capacity impact upon LOLE achieved by modeling the zones on a congestion-driven basis. Zones are developed from the process that utilizes two stages of PROMOD IV®. The steps are outlined in the Module E Tariff and the Resource Adequacy Business Practice Manual. This process also applies to the GE-MARS zones developed for PY 2018 in Section 5.1.2. One stage identifies the zones impacted by congestion and keys of the sign of the (MCC - \$/MWh). A second stage of PROMOD IV® determines the amount of transmission support (EITC and/or EETC – MWs) that is available into or out of the zone.

Figure 2.2 2009 GE MARS Modeled Zones is a geographical depiction of the resulting zones, that emerged from the raw output illustrated in Figure4.4.1-1. Figure 4.2.1-1 is a view of the more direct information resulting from the first stage 2009 PROMOD IV® run. The blue zones indicate zones where generation resources tend to have their schedules reduced as a result of managing congestion, and the red zones are zones where generation schedules are increased in order to maintain reliable operations to serve load. The yellow areas are indifferent to congestion at time of summer peak conditions. Previous Figure 3-1 "Zones and Parameters Modeled in 2009 GE MARS" is a sequel to the geographic zones in Figure 2.2 2009 GE MARS Modeled Zones, and shows the quantitative metrics (load, generation, and tie values) that were developed from the PROMOD IV® zonal analysis, and is an illustration of the input to the GE MARS LOLE program.

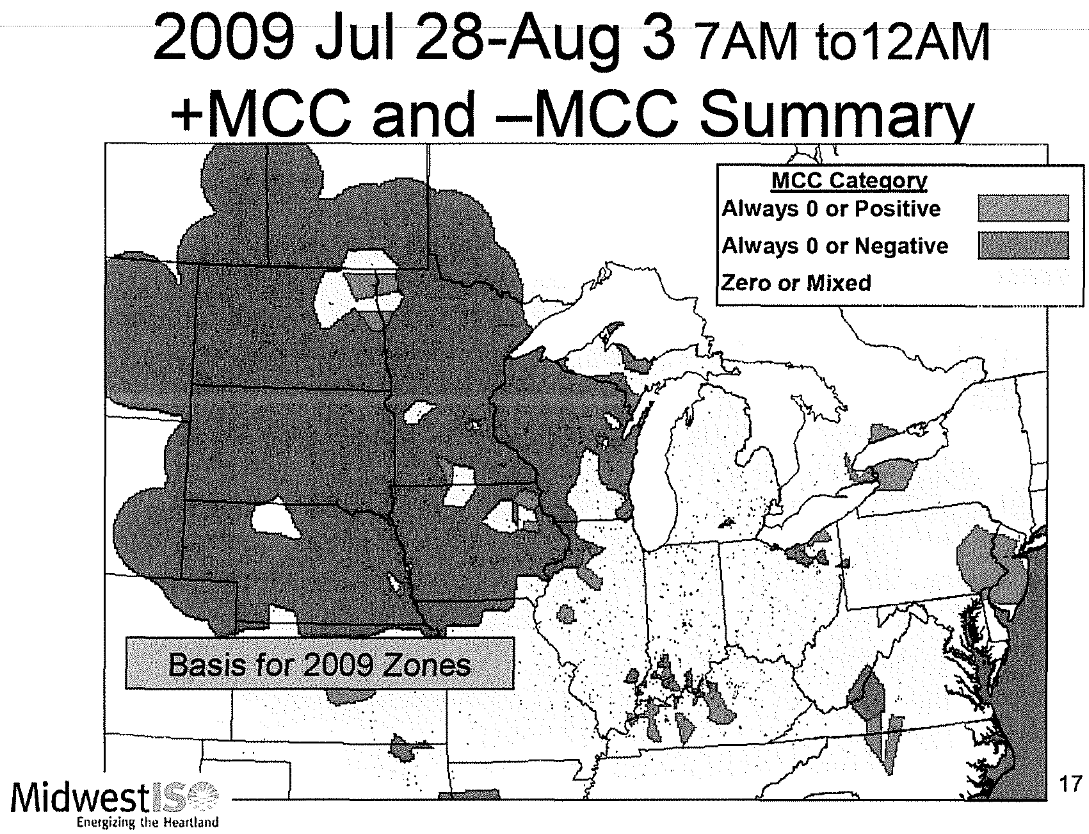


Figure 4.2.1-1 Illustration of clusters from first stage PROMOD IV® analysis results For Planning Year 2009

5. Years 2010 through 2018

5.1. GE MARS EFORd cases for 2013 and 2018

The GE MARS LOLE program was utilized again to determine planning reserve margins (PRM) for 2013 and 2018. The program utilization for these future years analysis was very similar to the assessment done previously for the initial 2009 planning year, but including the appropriate modeling changes in load forecast and unit additions or retirements. In both the 2013 and 2018 cases, Equivalent Forced Outage Rate Demand (EFORd) from GADS data over the historical period 2005 through 2008 was utilized as the modeled unit forced outage rate.

For 2013, the same 2009 internal zone configuration was utilized but without modeling the effects of congestion between zones. The 2013 Planning Year Reserve Margin was calculated without implicitly looking at the effects of congestion. This was accomplished by relaxing the internal tie limits between zones to infinity and allowed for the calculation of a congestion free PRM for 2013. A congestion adder was developed in Section 5.2 for 2013, so that it could be compared on the same basis as the bookend years 2009 and 2018. The second row in Table 7, shows the interpolated values for years 2010 through 2017, base on the 2009 and 2018 congestion adder values.

For 2018, the 2009 internal zones were not utilized and a new internal zone analysis was conducted to determine the zones and tie limits for 2018. These inputs were modeled and the planning reserve margin was calculated for a 2018 case, which included the effects of zonal tie limits. Then a case analysis similar to the 2013 analysis was conducted for 2018 in which the transmission constraints were relaxed and a congestion-free PRM was calculated.

5.1.1. Utilize 2009 External Equivalent zones

The same 2009 external equivalent zones configuration was utilized for the 2013 and 2018 analysis. External load growth and known unit additions and retirements where applied to the external system. The historically observed Effective External Tie Capacity (EETC) value of 4,186 MW was left unchanged. And in order to determine an appropriate level of support the external systems were again held to the same reliability level as the internal system.

5.1.2. New internal Zones for 2018

Internal zones for 2018 were determined using the same process as was used to determine zones for 2009. The model and data used for this analysis was obtained from the Joint Coordinated System Plan (JCSP) Study Reference Future and modified as necessary. The model does not include Regional Resource Forecast units nor any transmission expansions that do not already exist in the base 2018 power flow model. The first stage output of sign based MCC clusters form the PROMOD analysis is shown in Figure 5.1.2-1, and Figure 5.1.2-2 shows the final GE-MARS modeled zones. All candidate zones that were found to meet the 2,000 MW size thresholds (detailed in Section 2.2.2) were retained as modeled zones. Transfer limits were found for the 2 export zones and 1 import zone and the results input into the GE-MARS model. The quantitative values for each zones load, generation, and tie ratings for the 2018 GE-MARS model can be found in Figure 5.1.2-3.

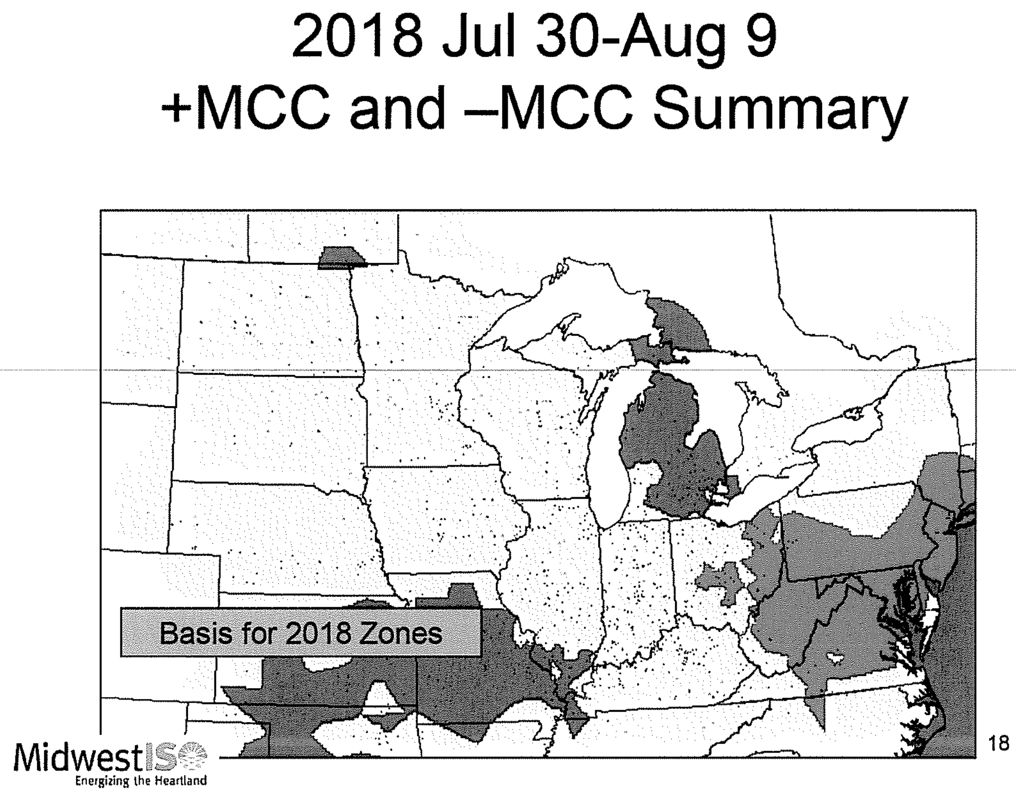


Figure 5.1.2-1 Illustration of clusters from first stage PROMOD IV® analysis results for Planning Year 2018

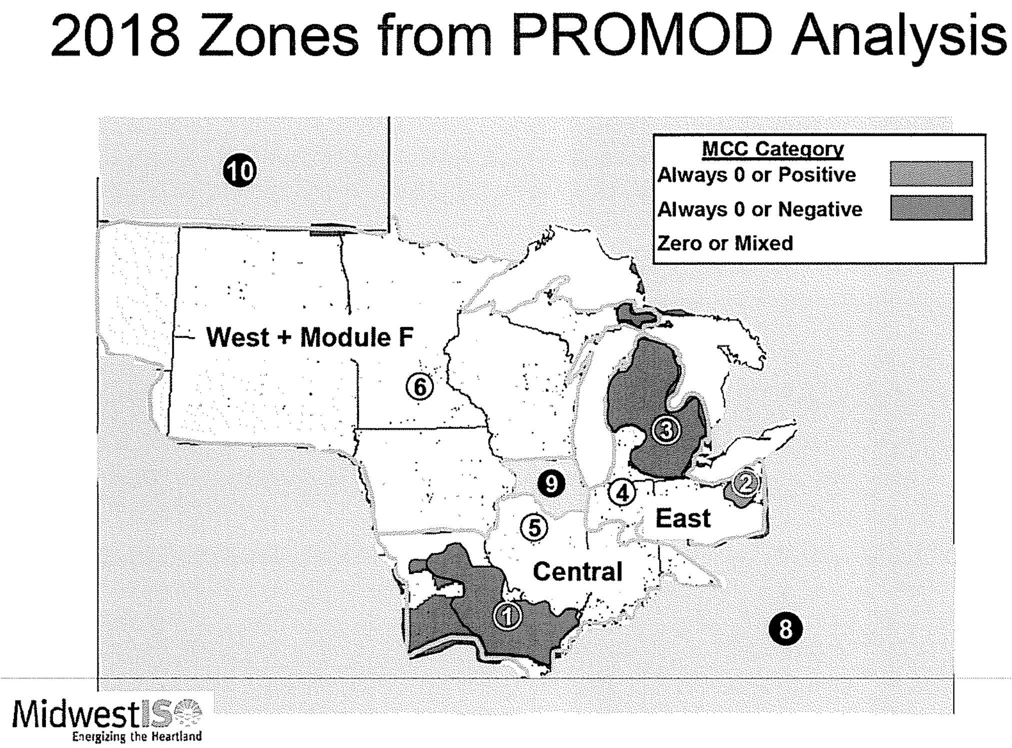


Figure 5.1.2-2 Congestion Based Zones Modeled in 2018

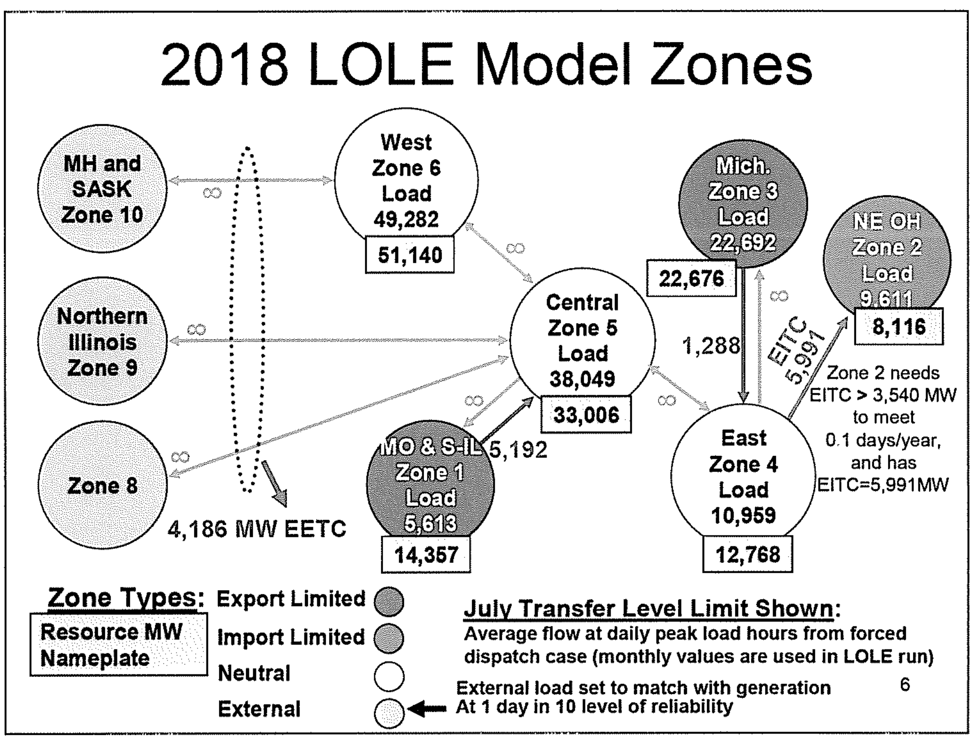


Figure 5.1.2-3 Zones and Parameters Modeled in 2018 GE MARS

5.2. Expected PRM for 2010-2018

The planning reserve margins, with no congestion, for the two periods of time years 2010 through 2012, and 2014 through 2017 were implicitly calculated by interpolating the row one results on a straight-line basis between the end years the year 2013 detailed cases that were done for years 2009, 2013 and 2018 (top row of Table7). The third row values were interpolated on a straight-line basis between the two values for 2009 and 2018. The expected $PRM_{SYSIGEN}$ from these interpolations can be seen for all years in Table 7, **where everything that was explicitly calculated is in red font.**

Table 7: Expected $PRM_{SYSIGEN}$ for 2010-2018

	Year									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
$PRM_{SYSIGEN}$ (No Congestion)	14.8%	14.8%	14.7%	14.6%	14.5%	14.6%	14.6%	14.6%	14.7%	14.7%
$PRM_{SYSIGEN}$ (Congestion Adder)	0.6%	0.8%	1.0%	1.2%	1.3%	1.5%	1.7%	1.9%	2.1%	2.3%
$PRM_{SYSIGEN}$ (With Congestion)	15.4%	15.6%	15.7%	15.8%	15.8%	16.1%	16.3%	16.5%	16.8%	17.0%

As the analysis and results indicate the amount of PRM needed to account for congestion increases in 2018 (second row in Table 7). In the 2018 simulation, the source of the increased congestion can be traced back to Zone 1 in figure 5.1.2-3. This zone has very high Capacity to Load Ratio and a limited amount of tie line capacity to export any surplus capacity that is not needed to meet internal load requirements. These trapped mega-watts can't be statistically shared with the rest of the Midwest ISO system.

The third row is the sum of rows 1 and 2, and since the congestion-free PRM_{SYSGEN} is reasonably stable (top row of Table 7), the increasing congestion (second row) is the reason behind the increased PRM_{SYSGEN} (With Congestion) in the third row. The overall PRM_{SYSGEN} (With Congestion) increasing by 1.6% over the 2009 value of 15.4% to a $PRM_{SYSIGEN}$ of 17.0% in 2018. The second row congestion values in Table 7 for years 2010 through 2017 were calculated by interpolating the fully calculated 2009 and 2018 second row values.

The Module E study process is both designed and obligated under the Tariff to coordinate the LOLE study results with the MTEP planning process. For the current 2009 study, the increasing congestion impact (second row in Table 7) is the most significant finding that needs to be brought to the attention of transmission planners. The transmission planning effort in MTEP09 will therefore include review of the trend for increased congestion suggested by the 2009 LOLE study, to determine if there is any correlation to planning findings. When investigated with study methods and tools traditionally utilized in conducting the transmission reliability assessment, possible outcomes, but not limited to the following, after MTEP review are that:

- The indicated congestion could be confirmed, or found not to correlate with an MTEP review.

- Key limiting facilities may be identified and addressed further
- With feedback from MTEP (including revised plans and incorporating that knowledge into the LOLE models), subsequent LOLE studies will converge to MTEP as a given future year becomes closer to the current Planning Year.

Appendix A Transmission Projects in Power-Flow

Projects from Model on Demand w/ In service date of 5/31/2010 or before; information as of 6/3/08

Name	ID	Type	Status	Effective
GRE-PROJECT-SHERMILL(60164)	1026	Network	Planned	6/1/2009
GRE-MISO-PROJECT-HNGYHLW(20181)	1279	MTEP B	Planned	7/1/2008
METC-MISO-WPSC-A-1228_ANR_new_load_08F	2384	MTEP A	Planned	8/1/2008
NIPS-MISO-project-FlintLkTowerRd1551	2489	MTEP B	Planned	7/1/2008
NIPS-MISO-project-Hiple2Xfr612	2492	MTEP A	Proposed	8/31/2008
FE-MISO-Babb 138 kV Cap_1327	2567	MTEP A	Planned	6/1/2009
FE-MISO-Cloverdale 138 kV Cap_1332	2571	MTEP A	Planned	6/1/2009
FE-MISO-Roberts - 138kV Cap_1335	2581	Network	Planned	6/1/2009
FE-MISO-West Akron - 138 kV Cap_1329	2583	MTEP A	Planned	6/1/2009
FE-MISO-rec. Walbridge Jct-Maclean_1324	2584	MTEP B	Proposed	6/1/2009
DEM-MISO-1500-Carmel146th69Cap1	2585	Non-Transferred	Planned	12/1/2008
DEM-MISO-1266-Hortonville69Cap	2595	Non-Transferred	Planned	6/1/2009
METC-MISO-658_Gaylord-Livingston-08F	2607	MTEP A	Planned	9/1/2008
METC-MISO-660_Keystone-Clearwater-09S	2612	MTEP A	Planned	6/1/2009
METC-MISO-1413_Bagley-Gaylord-09S	2613	MTEP A	Planned	6/1/2009
METC-MISO-988_Simpson-Batavia-08W	2616	MTEP A	Planned	12/31/2008
ITC-MISO-Bismarck-Troy-692-11S	2619	MTEP A	Planned	5/31/2010
ITC-MISO-Goodison-907-11S	2623	MTEP A	Planned	5/31/2010
DEM-MISO-632-GallagherHEGeorgetown13885Recond	2640	MTEP A	Planned	6/1/2009
DEM-MISO-807-DresserBk1-2LimitingEquipment	2642	MTEP A	Planned	6/1/2009
DEM-MISO-1200-SpeedBk3LimitingEquipment	2644	MTEP A	Planned	6/1/2009
DEM-MISO-852-CrawfordsvilleLafSE13819Recond	2649	MTEP A	Planned	12/31/2009
DEM-MISO-1262-HEDurgeeRd138	2655	MTEP A	Planned	6/1/2009
DEM-MISO-1502-TiptonWest230Sub	2656	Non-Transferred	Proposed	12/1/2008
DEM-MISO-1193-Nickel138Sub	2660	MTEP A	Planned	6/1/2009
DEM-MISO-1515-TrimbleSpeedGhent345Line	2661	MTEP B	Planned	10/1/2009
DEM-MISO-1254-CharlestownToCMC138Line	2662	MTEP A	Planned	12/31/2009
DEM-MISO-1512-AshlandToRochelle138UGline	2664	MTEP B	Proposed	12/31/2009
HE-MISO-MTEP-1322-Owensville Primary	2763	MTEP A	Planned	10/2/2008
HE_MISO_MTEP-1321-Napoleon_DecaturSS	2780	MTEP A	Planned	3/30/2009
METC-MISO-480-BrickyardJ-FelchRd	2783	MTEP B	Planned	6/1/2009
IPL Cumberland_Indian_Creek_40_[2007-08-01]	2790	MTEP A	Planned	6/1/2009
AMMO-MISO-project-719-LabadieBreakers	2799	MTEP A	Planned	6/1/2009
ITC-MISO-1302_Hines Equipment Replacement_ITC	2814	MTEP A	Planned	12/31/2008
METC-MISO-Parmenter-08fall	2868	Network	Planned	10/1/2008
METC-MISO-1438-Potvin-08fall	2870	MTEP A	Planned	10/1/2008
METC-MISO-1837-VanBuren-08sum	2872	MTEP B	Planned	7/1/2008
METC-MISO-1444-Dublin-09sum	2874	MTEP A	Planned	6/1/2009
METC-MISO-981-Wabasis-09sum	2876	MTEP A	Planned	6/1/2009
SIGE-MISO-Prj1001-1002-OakGr-NE138kV-n-Trf	2886	MTEP B	Planned	5/30/2009

SIGE-MISO-Prj1023-ScottTwp_Elliott138kV	2888	MTEP B	Planned	5/30/2009
WPSC-MISO-B-1213_Vestaburg 6MVAR Cap	2924	MTEP B	Planned	12/31/2008
WPSC-MISO-B-1579_Garfield-Grawn Rebuild	2926	MTEP B	Planned	7/31/2008
WPSC-MISO-C_1577-Copemish-Bass Lake Rebuild	2934	MTEP B	Proposed	12/31/2008
WPSC-MISO-C_1586-Gaylord-Advance Rebuild	2935	MTEP B	Planned	12/31/2009
WPSC-MISO-C_1227-Gaylord-Gaylord OCB Rebuild	2936	MTEP A	Planned	12/31/2009
WPSC-MISO-C_1315-Grand Trvse-East Bay Rebuild	2937	MTEP B	Planned	12/31/2009
WPSC-MISO-C_1219-Lake Cnty-Plains X Rebuild	2939	MTEP B	Planned	12/31/2009
WPSC-MISO-B-1211_Gnd Trvse-Grawn Rebuild	2952	MTEP B	Planned	12/31/2009
CWLP-CHATHAM-project-08summer_3	2957	MTEP A	Planned	7/1/2008
CWLP-DALLMAN-project-09summer_4	2958	MTEP A	Planned	7/1/2009
CWLP-INTERSTATE-1552-project-09fall_1	2959	MTEP B	Planned	9/1/2009
WPSC-MISO-C_Gray-1965-138-69 Transormer	2979	MTEP B	Planned	3/2/2009
ATC_(177)_GDP-HWY22_345_T2-1113	3120	MTEP A	Planned	12/1/2009
ATC_(177)_J36Rebuild_WHB-CAR	3121	MTEP A	Planned	6/1/2009
ATC_(339)_Remove_Boxelder_Temporary_Cap_Bank	3124	MTEP A	Planned	6/1/2009
ATC_(345)_new-Clintonville-WernerW138kV	3125	MTEP A	Planned	11/24/2008
ATC_(345)_rebuilding-Badger-Clintonville138kV	3126	MTEP A	Planned	12/1/2009
ATC_(345)_rebuilding-Badger-WShawano138kV	3127	MTEP A	Planned	6/1/2009
ATC_(345)_rebuilding-WhiteClay-EShawano138kV	3128	MTEP A	Planned	10/1/2009
ATC_(352)_CON-IRGR138_v29	3132	MTEP A	Planned	2/1/2009
ATC_(352)_IRGR-ASPN138	3134	MTEP A	Planned	8/1/2009
ATC_(570)_ROR_to_ELK_138R_Conv_TUR_on_69_Radial	3138	MTEP A	Planned	3/31/2009
ATC_(571)_N_Madison-Huiskamp_138kV_Line	3140	MTEP A	Proposed	12/15/2008
ATC_(877)_oc_phase_1_-_kansas-norwich_loopin	3146	MTEP A	Proposed	6/1/2009
ATC_(877)_oc_phase_1_-_oak_creek_xfmr	3147	MTEP A	Proposed	6/1/2009
ATC_(877)_oc_phase_1_-_oc_-_ramsey_upgrade	3148	MTEP A	Proposed	6/1/2009
ATC_(886)_NorthLake_aka_Cedar_retirements_ver2	3154	MTEP A	Proposed	3/26/2009
ATC_(1268)_Kilbourn_138_and_Artesian_138_Cap_banks	3157	MTEP B	Proposed	4/30/2009
ATC_(1279)_North_Beaver_Dam_Cap_Bank	3159	MTEP B	Proposed	6/1/2009
ATC_(1282)_Osceola_Caps_1x4_08	3162	MTEP B	Proposed	6/1/2009
ATC_(1461)_Green_Lake_Wind-G376	3164	MTEP A	Suspended	9/1/2009
ATC_(1463)_Twin_Creeks-G384	3165	MTEP A	Planned	9/1/2009
ATC_(1553)_Hiawatha_Cap_1x16_3_v29	3167	MTEP B	Planned	6/1/2009
ATC_(1555)_Perkins_Cap_2x16_3_v29	3169	MTEP B	Proposed	8/15/2009
ATC_(1667)_Pine_River_Ring_Bus_and_Caps	3176	MTEP B	Proposed	11/14/2009
ATC_(1668)_Munising_Cap_2x4_08	3177	MTEP B	Planned	8/11/2008
ATC_(1669)_Roberts_2ndCap_1x4_08	3178	MTEP B	Planned	8/1/2008
ATC_(1676)_LAnse_Cap_1x4_08	3182	MTEP B	Proposed	9/15/2009
ATC_(1677)_Cornell-Chandler_167F	3183	MTEP B	Proposed	5/1/2009
ATC_(1679)_Richland_Center_Olson_Capacitor_Bank	3184	MTEP B	Proposed	6/2/2009
ATC_(1680)_Walworth-North_Lake_Geneva_69kV_Uprate	3185	MTEP B	Proposed	6/1/2009
ATC_(1681)_Uprate_NLG_to_LG_69kV_Line	3186	MTEP B	Proposed	6/1/2009
ATC_(1682)_Rebuild_Crivitz-HiFalls69kV_T2-336	3187	MTEP A	Planned	6/1/2009
ATC_(1940)_M-38_Cap_1x8_1	3204	MTEP B	Proposed	6/1/2009
ATC_(1945)_Upgrade_Sheepskin_Cap_Bank	3206	MTEP B	Proposed	4/12/2010
ATC_(TtoD)_TD_ALTE_Sun_Valley	3222	Network	Proposed	6/24/2009
ATC_(TtoD)_TD_Global_Renewable_Energy	3230	Network	Proposed	1/1/2009
ATC_(TtoD)_TD_MGE_Oakridge	3236	Network	Proposed	6/1/2009

ATC_(TtoD)_TD_schofield	3238	Network	Proposed	12/31/2009
ATC_(TtoD)_TD_SPRECHER_MGE_idev_SPR2xfmr2009Sa	3239	Network	Proposed	6/1/2009
ATC_(TtoD)_SBU_T-D	3250	Network	Proposed	6/1/2009
ATC_(TtoD)_T-D_7thST	3253	Network	Proposed	6/1/2009
ATC_(TtoD)_2nd_edgewood_t-d_xfmr	3260	Network	Proposed	9/1/2008
ATC_(TtoD)_2nd_maple_xfmr	3261	Network	Proposed	5/1/2009
ATC_(TtoD)_3rd_center_xfmr	3264	Network	Proposed	6/1/2009
ATC_(TtoD)_3rd_summit_t-d	3269	Network	Proposed	1/1/2009
ATC_(TtoD)__hayes_xfmr_replacement	3270	Network	Proposed	6/1/2009
ATC_(TtoD)_montana_t-d	3276	Network	Proposed	3/1/2009
ATC_(TtoD)_replace_nicholson_xfmr	3278	Network	Proposed	6/1/2009
ITC-MISO-1308_B3N_Interconnection	3284	MTEP A	Planned	12/31/2009
ITC-MISO-1875-G503	3288	MTEP A	Planned	12/31/2008
ATC_(1942)_uprate_Atlantic_Tr	3339	MTEP B	Planned	6/1/2009
ATC_(1943)_uprate_M38_Tr	3340	MTEP B	Planned	6/1/2009
ATC_(1665)_Laurium-1_Rebuild	3376	MTEP B	Planned	6/30/2008
ATC_(877)_oc_phase_1_-oak_creek-allerton_upgrade	3378	MTEP A	Proposed	6/1/2009
ATC_(TtoD)_fromMGE_2009_WLTxfmr1and2a	3379	Network	Planned	6/1/2009
ATC_(345)_revised_Morgan-CW-WernerW_T2_1113_345	3387	MTEP A	Planned	12/2/2009
ATC_(572)_Menominee_138_69kV_TRF	3388	MTEP A	Proposed	11/1/2008
ATC_(1683)_Rebuild_SunsetPt-Pearl69kV	3389	MTEP B	Proposed	6/1/2009
ATC_(1470)_Whistling_Wind-G483(combined)	3396	MTEP A	Suspended	9/1/2009
NIPS-MISO-project-BentonCoWind1615	3397	MTEP A	Planned	5/1/2008
SMP-MISO-GEN-ADDED09	3402	Non-Transferred	Planned	7/15/2009
SMP-MISO-BLOOM-GEN09	3403	Non-Transferred	Planned	7/15/2009
SMP-MISO-Rutland-1633	3404	MTEP B	Planned	7/15/2008
CWLP-DALLMAN-project-09summerV2	3410	MTEP A	Planned	7/1/2009
SMP-MISO-LAKECITY-AREA	3415	Non-Transferred	Planned	1/15/2009
ATC_(TtoD)_brookdale_3rd_xfmr	3419	Network	Planned	6/15/2009
ATC_(TtoD)_raymond	3420	Network	Planned	10/7/2008
ATC_(877)_oc-phase-1	3421	MTEP A	Proposed	6/12/2009
DEM-MISO-1563-TodhunterToAKSteelF5686Recond	3425	MTEP B	Planned	10/15/2008
DEM-MISO-1564-RoseburgSwSta69kvCap	3426	Non-Transferred	Planned	6/1/2009
DEM-MISO-1566-TodhunterToAKSteelF5682Recond	3427	MTEP B	Planned	11/15/2008
DEM-MISO-1567-RockiesExpress-REX	3428	Non-Transferred	Planned	11/1/2008
SMP-MISO-Litchfield-Cap08 [2008-02-05 09:56:34]	3447	Non-Transferred	Planned	7/15/2008
DEM-MISO-1514-WabashRiverStaunton23002uprate	3452	MTEP B	Planned	6/1/2009
HE-MISO(1323)-Sandborn	3457	Non-Transferred	Planned	9/8/2008
XEL-1371-BLACKDOG-WILSON2-UPGRADE	3508	MTEP B	Planned	6/1/2009
XEL-1486-MARYLAKE-BUFFALO	3520	Non-Transferred	Planned	12/1/2008
XEL-1457-HAZEL	3527	MTEP A	Planned	6/1/2009
XEL-1548-LACROSSE	3533	MTEP B	Planned	6/1/2009
XEL-1545-MANKATO_115KV_LOOP	3535	MTEP B	Planned	9/1/2009
XEL-1548-MONROECO_CAPBANK	3539	MTEP B	Planned	6/1/2009

XEL-1368-1369-1370-NEWRICHMOND	3541	MTEP B	Planned	6/1/2009
XEL-1373-NEWULM-TS	3542	MTEP B	Planned	6/1/2009
XEL-1455-MERP-RIVERSIDE	3544	MTEP A	Planned	6/1/2009
XEL-1487-SOMMERSET	3547	Non-Transferred	Planned	6/1/2009
XEL-WASECA	3550	Non-Transferred	Planned	8/1/2008
XEL-1489-WOODBURY-TANNERSLAKE	3553	MTEP A	Planned	6/1/2009
XEL-385-825WIND	3558	MTEP A	Planned	11/1/2007
XEL-1457-BRIGO	3559	MTEP A	Planned	6/1/2009
XEL-CHANARAMBIE-3RDTR	3567	Non-Transferred	Planned	12/30/2008
AMMO-MISO-project857-155Joachim345kV	3599	MTEP A	Planned	9/3/2008
AMIL-MISO-725-726-project-WedronSubstation	3605	MTEP A	Planned	6/1/2009
AMIL-MISO-865-project-HavanaCubaMonmouth	3611	MTEP A	Planned	6/1/2009
ATC_(TtoD)_3rd_granville_xfmr	3613	Network	Proposed	6/1/2009
AMIL-MISO-1232-project-MarigoldSub	3615	MTEP B	Planned	10/1/2008
AMIL-MISO-project-2058-ConocoPhilip138kV	3618	MTEP B	Planned	9/30/2009
AMMO-MISO-project2072-BrickHouseSub	3621	MTEP B	Planned	10/1/2008
ALTW_Arnold-Washburn_1739-161kV_Upgrade	3631	MTEP B	Planned	12/31/2009
ALTW_Salem-1287_345-161kV_448_MVA	3632	MTEP A	Planned	6/1/2009
ITC-MISO-1870-CLYDE	3633	MTEP B	Planned	5/1/2009
ITC-MISO-1871-HURST	3636	MTEP B	Planned	5/1/2009
ITC-MISO-1872-SCIO	3637	MTEP B	Planned	12/31/2008
ALTW_Ottumwa-1641_161kV_50MVAR	3638	MTEP B	Planned	12/31/2009
ALTW_Appanoose-1642_161kV_50MVAR	3639	MTEP B	Proposed	12/31/2009
ALTW_Anita-1643_161kV_24MVAR	3640	MTEP B	Proposed	12/31/2009
ALTW_Grand_Junction-1644_161kV_24MVAR	3641	MTEP B	Proposed	12/31/2009
ALTW_Leon-1645_69kV_7MVAR	3642	Non-Transferred	Proposed	12/31/2009
ALTW_Excel-1773_69kV_6MVAR	3643	Non-Transferred	Planned	12/31/2008
ALTW_Hills-Washington-1755_69kV_Rbld	3644	Non-Transferred	Planned	12/31/2008
ALTW_N_Cntrville_69kV-1772_7MVAR	3645	Non-Transferred	Planned	12/31/2009
METC-MISO-1819-Felch-Croton	3652	MTEP B	Planned	12/31/2009
METC-MISO-1797-Almeda-Sagriv	3653	MTEP B	Planned	5/31/2010
METC-MISO-1794-Argenta-Verona	3669	MTEP B	Planned	6/1/2009
ALTW_1522_6th-Beverly_161kV	3697	MTEP B	Planned	4/1/2009
ALTW_1618_Heron Lake-Lakefield_161kV	3698	MTEP B	Planned	12/31/2009
ALTW_Grand_Mound-1619_161kV	3699	MTEP B	Planned	12/31/2008
XEL-1547-IRONWOOD_2ND_TR	3701	Non-Transferred	Planned	6/1/2009
ALTW_1289_Marshalltown-Toledo_115V	3713	MTEP A	Planned	12/31/2008
ALTW_Hiawatha-Lws_Flds-1342_161-115kV	3715	MTEP A	Planned	6/1/2009
OTP-MTEPC-3754-CASSLKXFMR	3754	MTEP B	Planned	7/1/2009
WPSC-MISO-NETWORK_Odawa	3788	Network	Planned	7/1/2008
HE SandBorn New 2095	3814	MTEP A	Planned	9/1/2008
OTP-1462-G380 [2008-02-29 11:34:09]	3819	MTEP A	Suspended	10/1/2009
GRE-MISO-PROJECT-BGFSH_FRMG(54451)	4008	Network	Planned	6/1/2009
GRE-MISO-PROJECT-KRMRLK(53801)	4010	Network	Planned	6/1/2009

GRE-MISO-PROJECT-LWRNCTP(20138)	4011	Network	Planned	11/1/2008
GRE-MRO-PROJECT-2086-WILSONSRC	4014	MTEP A	Planned	10/1/2008
GRE-PROJECT4495-ENTPPK_CRKDLK(20152)	4016	MTEP A	Planned	12/1/2009
GRE-PROJECT-TOWER(1021)(for mp)	4017	MTEP A	Planned	1/1/2010
GRE-MRO-PROJECT-BBP(20143)	4018	MTEP A	Planned	9/1/2008
GRE-MISO-PROJECT-SARTELL(20225)	4019	Network	Planned	9/1/2009
XEL-MINN_RIVER2	4044	MTEP A	Planned	6/1/2009
XEL-MRO-PROJECT-PRESCOTT_CAPBANK	4049	Non-Transferred	Planned	6/1/2009
XEL-MRO-PROJECT-G417	4050	MTEP A	Planned	12/1/2008
ATC_(570)_SW_Delavan_to_North_Shore_to_BOL_69	4085	MTEP A	Planned	8/15/2008
ALTW-MRO-PROJECT-09SPLL.PRJ [2008-03-28 12:23:07]	4100	Network	Planned	4/1/2009
ALTW-MRO-PROJECT-10SPPK.PRJ [2008-03-28 12:24:31]	4101	Network	Planned	4/15/2010
OTP-274_275-AP-CAN [2008-03-28 12:32:19]	4103	MTEP A	Planned	8/1/2008
ALTW-MRO-PROJECT-10WIPK.PRJ [2008-03-28 12:33:18]	4105	Network	Planned	1/31/2010
OTP-MTEPC-1792-CSLTN ETHANOL	4107	MTEP B	Planned	10/1/2008
FE_1610_avon-tr	4180	MTEP A	Planned	6/1/2009
Lakeview cap	4184	MTEP B	Planned	9/1/2008
FE-nfalls-tr-4185	4185	MTEP B	Planned	6/1/2009
FE-tangy-tr-1609	4187	MTEP B	Planned	6/1/2009
FE-w-medina-1589	4188	MTEP B	Planned	6/1/2009
ATC_(339)_Jefferson-Stonybrook_138_kV_and_Uprates	4227	MTEP A	Planned	5/31/2009
ATC_(2057)_Warrens_T-D_w_line_ext	4232	MTEP B	Proposed	12/1/2009
ATC_(TtoD)_TD_Vienna	4234	Network	Proposed	6/1/2009
XEL-1956-WILMARTH-BLUELAKE	4254	MTEP B	Planned	12/1/2009
METC-MISO-1817-Midland	4257	MTEP A	Planned	9/1/2008
METC-MISO-1442-Pingree	4258	MTEP A	Planned	7/1/2008

Appendix B Load Forecast Uncertainty (LFU) Final Report

Scope

Apply MISO stakeholder expertise in load forecasting together with the resident MISO expertise to determine the annual uncertainty associated with the variance between actual load and the 50/50 forecast load. The LFU is for the 2009 planning period and for the subsequent nine planning years. The work product of the LOLEWG-LFU Task Team will be recommended and presented to the LOLEWG by October 10, 2008. Load Forecast Uncertainty is the result of weather, economic, and demographic factors. It is not forecast error or one's ability to forecast accurately given the limitations of the models available for use.

Executive Summary

The Load Forecast Uncertainty Task Team recommends the use of the Summation of the NERC Variances method to calculate the load forecast uncertainty value necessary for GE MARS. This method produces a sigma value of 4.04% in the summer and a sigma value of 4.08% in the winter. The benefits of using the Summation of the NERC Variances are that the method has a solid methodology and most of the work has been completed through the NERC Load Forecasting Working Group (LFWG). The Load Forecast Uncertainty Task Team also recommends the use of a constant 4.04% summer LFU and 4.08% LFU value for years 2-10 analysis with one sensitivity case with a 5 year out LFU value of 8.95% in the summer and 7.14% in the winter.

Overview

The Load Forecast Uncertainty (LFU) Task Team was created to help develop a recommendation of the methods in which to obtain a value for Load Forecast Uncertainty to the Loss of Load Expectation Working Group (LOLEWG). Initial work had been started by Ryan Westphal of Midwest ISO previous to the forming of the LFU Task Team. His work was the starting point for this group. This group was comprised of subject matter experts from the MISO stakeholder community. This group typically meets on a monthly basis, half day before the full day LOLE WG meeting.

1. Monthly Peak Comparison

The monthly peak comparison work was the starting point in trying to determine a value for LFU. The summer and winter assessments use the same method for their determination of the 90/10 and 10/90 bands. The Load Forecast Uncertainty (LFU) value is derived from variance analysis to determine how likely monthly peak forecasts will deviate from actual monthly peak load. In order to establish a Load Forecast Uncertainty value three years of real-time load data was compared to forecasts for those same periods. Load forecasts for the months of June, July and August for summer and December, January, and February for winter were adjusted for the reported demand side management programs to arrive at coincident Net Internal Demand forecast values. Those monthly forecasts were compared to the actual monthly peak loads of the same period and the differences compiled into a sample space from which to derive a standard deviation. A load forecast uncertainty of approximately 4.1% for the summer was calculated using this methodology. A graph of the monthly peaks is available in the appendix (Graph 1.1). For this model a normal distribution is assumed. From the graph we can see that the sample space for data is three years.

2. Weather Sorting Model

A weather sorting model was developed to evaluate LFU. The weather sorting model gives us a long statistical history. Since this model derives its statistical analysis from weather a long history of load is not needed. A long history of weather variables is easily obtained. The weather variables, specifically heat index, are then used to determine the sigma of the heat index over a 25 year history (Graph 2.1). To capture how load is affected by weather at the entire MISO footprint level a composite temperature is developed. The composite heat index is a load weighted average of the heat index at each weather station that is selected to represent the heat index for that balancing authority. To see how load responded to the composite heat index at each daily peak, the load and composite heat index are plotted together. The result of this plot is available in the appendix (Graph 2.2). From this graph we can use the equation to determine the number of MW's that are affected for each degree of heat index. If we assume that the equation representing weather above 72 degrees F is linear we get an equation of:

$$Y(x) = 1742 * x - 62332 \tag{1}$$

Where Y equals MW's and x equals degrees F. If we take the derivative of equation (1) we get the following equation.

$$\frac{dy}{dx} = 1742 \tag{2}$$

Equation 2 states that for every unit change in x there is a 1742 unit change in y or for every change in degree F there is a 1742 MW change in load. From the model we can now construct the following table (2.1).

Table 2.1: Results to calculate LFU

(1)	(2)	(3)	(4)	(5)
Heat Index(F)	Standard Deviations	Delta Heat Index	MW/deg	MW
80.9	-3	-8.1	1742	-14110.2
83.6	-2	-5.4	1742	-9406.8
86.3	-1	-2.7	1742	-4703.4
89	0	0	1742	0
91.7	+1	2.7	1742	4703.4
94.4	+2	5.4	1742	9406.8
97.1	+3	8.1	1742	14110.2

Column number 5 is calculated by multiplying columns 3 and 4 together. Using this method a sigma of 4.4% is calculated.

3. Other Studies

A presentation was given showing the different values and method other regions are using for their studies. Looking at other regions we can evaluate a reasonable number to apply in the Midwest ISO LOLEWG study. From the presentation a "Band of Reasonability" of 4-5% sigma was created. A link to the presentation is provided below.

http://www.midwestiso.org/publish/Document/81d7e_11b6e66e758_-7a4b0a48324a?rev=1

4. Summation of the NERC Variances

NERC develops its own uncertainty bands for each of the NERC regions. This method will use these uncertainty bands with a load weighted variance calculation to determine the MISO-wide sigma. Three NERC regions have portions of their load in MISO. Those three regions are MRO US, SERC and RFC. To calculate the weights each MISO load balancing authority is assigned to its appropriate NERC regions and then the percent of the MISO load within the region is the weight used for the calculation. The NERC bands are stated in 90/10 and 10/90 projections. To convert those to a sigma value we divide by 1.28. This corresponds to the x-value from the unit normal distribution for the 90/10 and 10/90 bands. The general equation for summing random variables variances is used to determine the weighted variance for MISO.

(1) $var(a_x x + a_y y) = a_x^2 * var(x) + a_y^2 * var(y) + 2 * cor(x,y) * a_x * std(x) * a_y * std(y)$

(2) $var(x) = std(x)^2$

Plugging (2) into (1)

(3) $std(a_x x + a_y y)^2 = a_x^2 * std(x)^2 + a_y^2 * std(y)^2 + 2 * cor(x,y) * a_x * std(x) * a_y * std(y)$

Expanded to three variables

$$std(a_x x + a_y y + a_z z)^2 = a_x^2 * std(x)^2 + a_y^2 * std(y)^2 + a_z^2 * std(z)^2 + 2 * cor(x,y) * a_x * std(x) * a_y * std(y) + 2 * cor(x,z) * a_x * std(x) * a_z * std(z) + 2 * cor(y,z) * a_y * std(y) * a_z * std(z)$$

If $cor(x,y) = 1$

$$std(x+y) = \sqrt{a_x^2 * std(x)^2 + a_x^2 * std(y)^2 + 2 * a_x * std(x) * a_y * std(y)}$$

$$std(x+y) = \sqrt{[a_x * std(x) + a_y * std(y)]^2}$$

$$std(x+y) = a_x * std(x) + a_y * std(y)$$

If $cor(x,y) = 0$

$$std(x+y) = \sqrt{a_x^2 * std(x)^2 + a_y^2 * std(y)^2}$$

As we can see from the above equation we have to make an assumption about the correlation between the three regions. It was suggested within the LFU Task Team to use the MISO coincident factor of .96 in the summer and .97 in the winter as the correlation between the three regions. Table 4.1 and 4.2 within the appendix summarizes the results of the Summation of the NERC Variances. The Summation of the NERC Variances produces a sigma of 4.04% in the summer and 4.08% in the winter.

5. 2-10 Year Analysis

The LFU Task Team ran the Summation of NERC Variance results through the MARS software to help determine how to model LFU in the 2-10 year LOLE analysis. Three summer LFU numbers were run in the MARS software, first year LFU of 4.04%, 5 year LFU of 8.95% and 10 year LFU of 12.50%. Graph 5.1 in the appendix summarizes all values calculated from the Summation of NERC Variances. The results of the analysis are shown in the following table 5.1.

Table 5.1 MARS results with increasing LFU

	% Reserve Margin	Total System MW	Total System Demand	Incremental MW needed to meet 1 day in 10
Year 1	13.88%	115,786	101,671	0
Year 5	17.38%	129,551	110,372	13,765
Year 10	30.04%	151,051	116,160	35,265

From the table we see that in year 10 a 30.04% reserve margin is needed to meet the 1 day in 10 criteria. The LFU Task Team believes this is unreasonable and if the LFU is grown it must be capped from growing at some point. The LFU Task Team believes that capping the LFU at the 5 year number would be representative of the time it takes to get capacity built and recommends that the LFU be capped at the 5 year value.

The LFU Task Team further discussed that holding the LFU constant at the 1 year value for all years would better represent what reserve margins that can be expected to be seen in each year. It was thought that once we get the each subsequent year that an LFU value would be closer to the 1 year out value, meaning that, once you get to year 5 the LFU value will be a 1 year out LFU value.

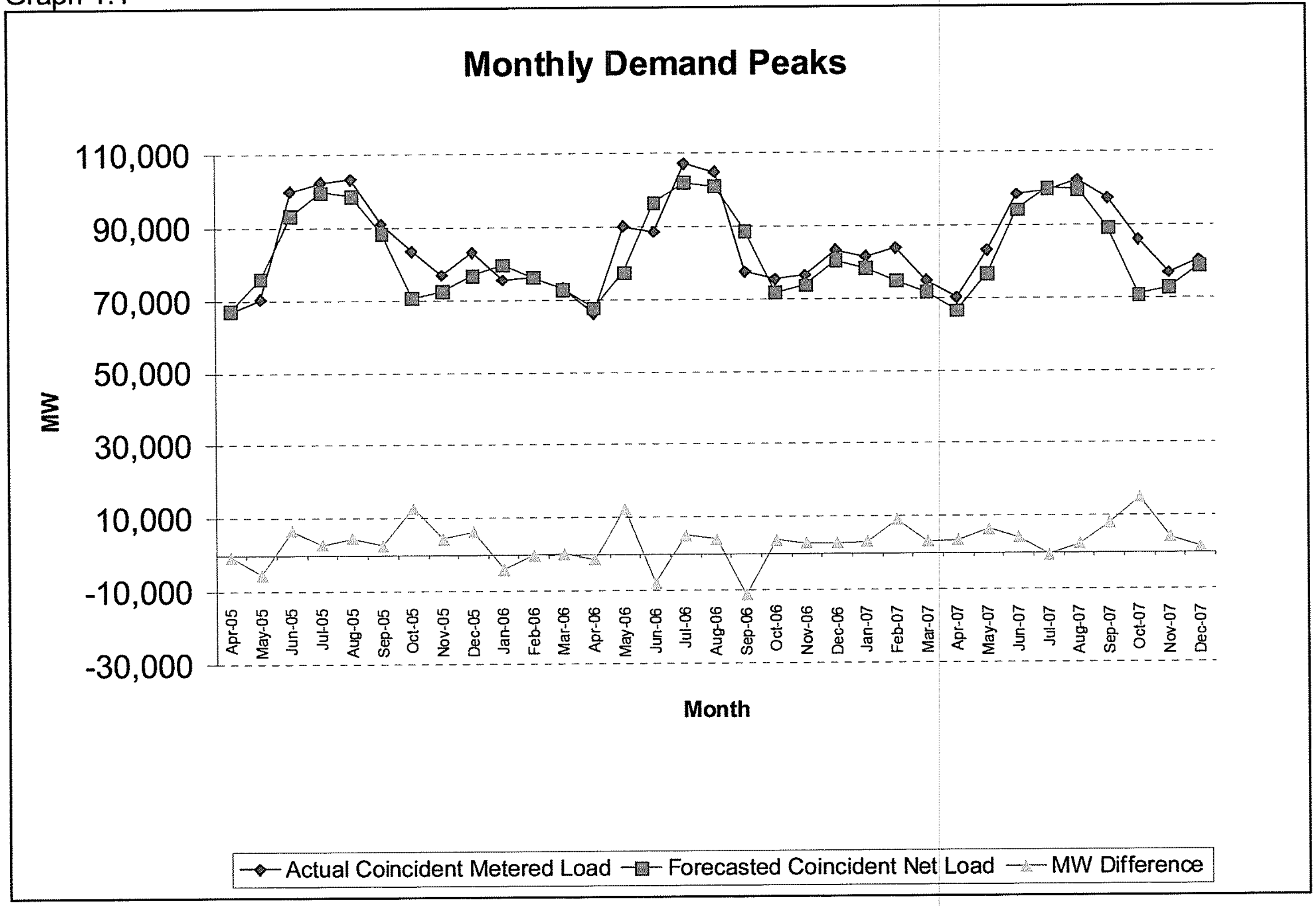
6. LFU Task Team Recommendation

The LFU Task Team is recommending the use of the Summation of the NERC Variances to the LOLE WG. This method has the benefits of being tried and tested before and much of the work is complete through the NERC LFWG. Also looking at the other studies performed in the LFU Task Team each study results seem to converge to a similar number. The sigma values that are calculated through the Summation of the NERC Variances are a sigma of 4.04% in the summer and 4.08% in the winter. In the future of the LFU Task Team the Weather Sorting model will be helpful in sanity checking and possible using it in a future study where weather correcting is necessary.

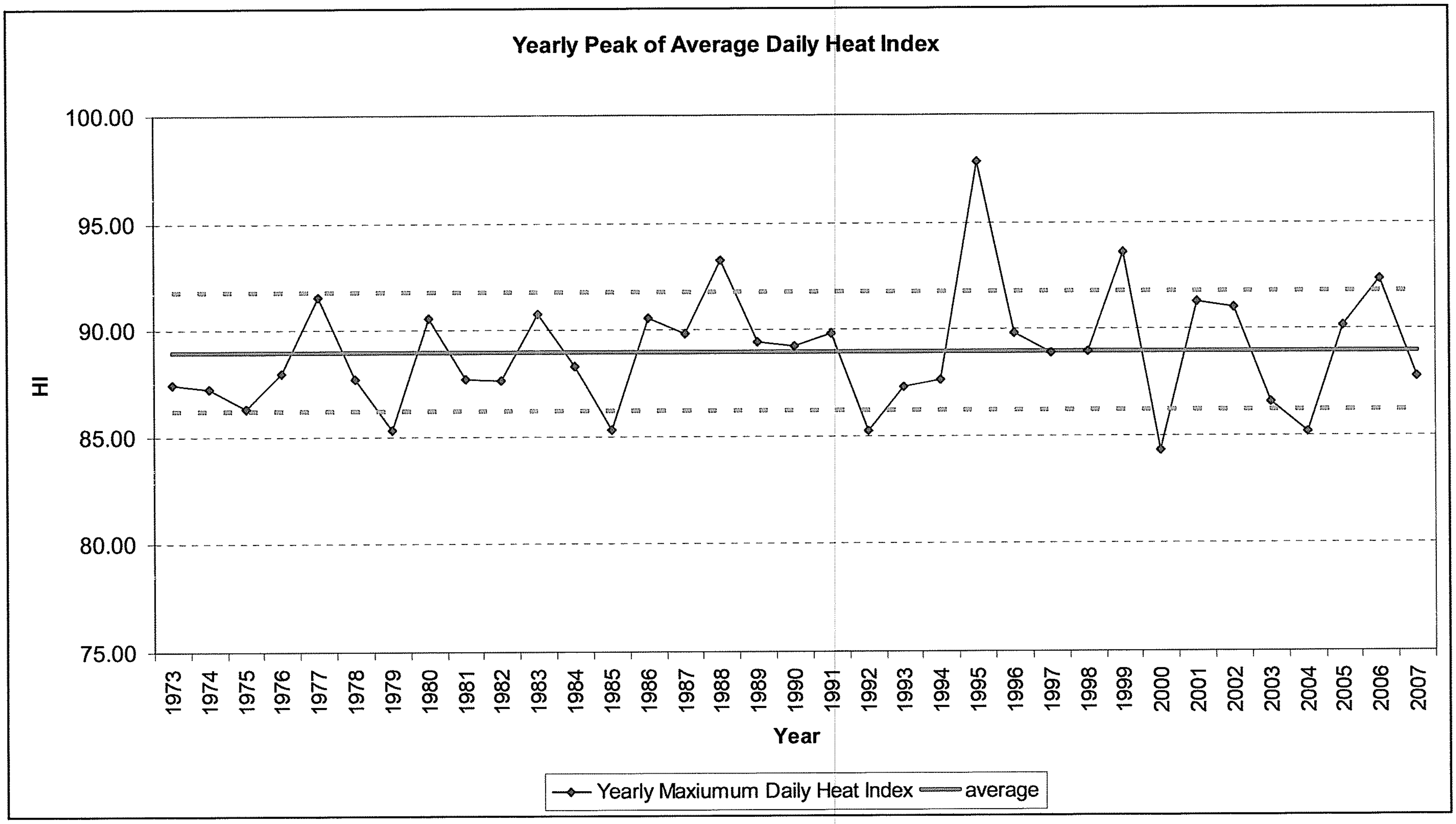
The LFU Task Team recommends running years 2-10 with a fixed 1 year out LFU of 4.04% in the summer and 4.08% in the winter. The LFU Task Team also recommends running one case with a 5 year out value or 8.95% in the summer and 7.14% in the winter.

LFU Appendix

Graph 1.1



Graph 2.1



Yearly Peak of Average Daily Heat Index
100.00
95.00
90.00
85.00
80.00
75.00
HI
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
Year
Yearly Maxiumum Daily Heat Index
average

Graph 2.2

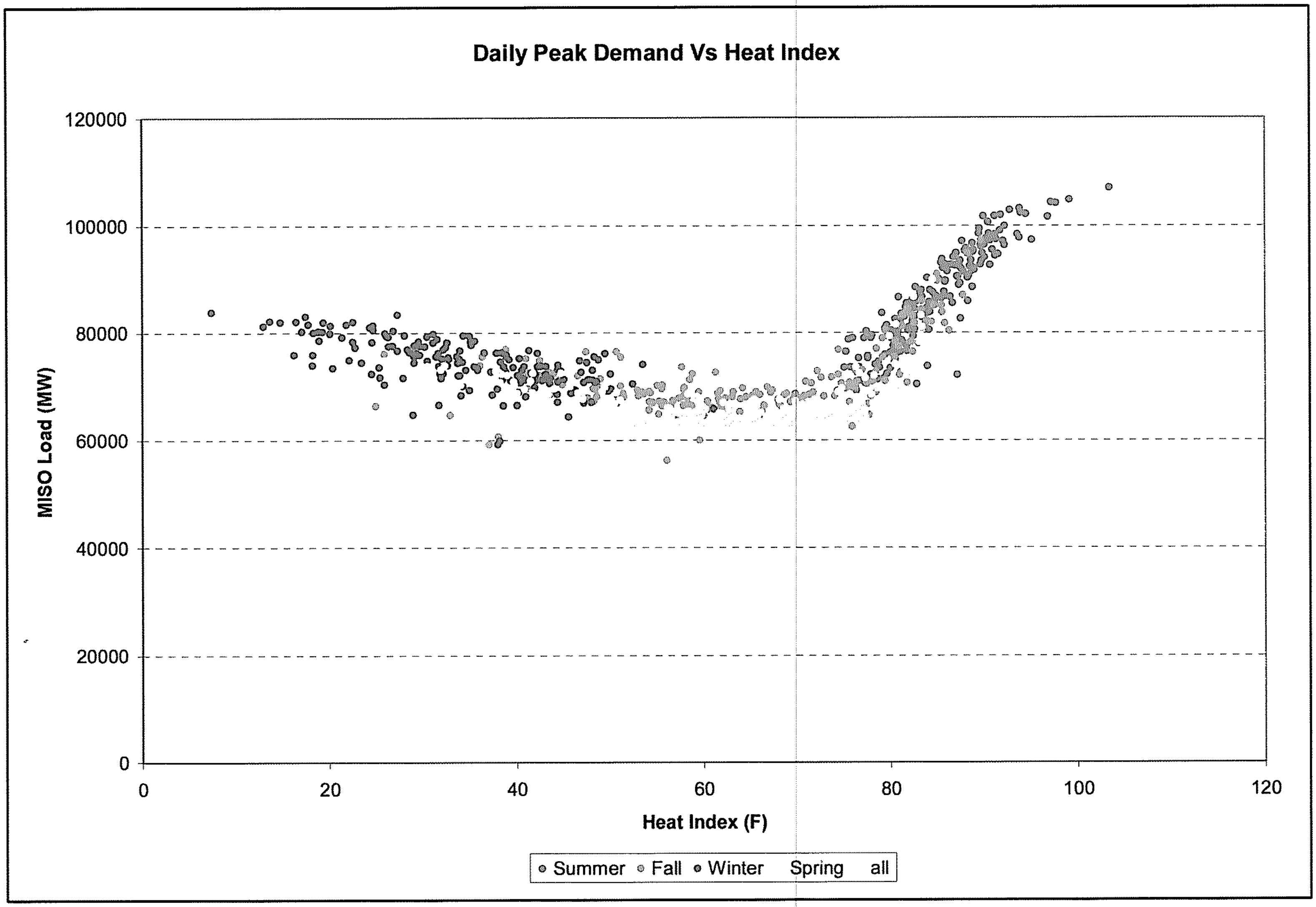

Daily Peak Demand Vs Heat Index
120000
100000
80000
60000
40000
20000
0
MISO Load (MW)
0
20
40
60
80
100
120
Heat Index (F)
Summer
Fall
Winter
Spring
all

Table 4.1

Summer

Year		WEIGHTING FACTOR	(WEIGHTING FACTOR)^2	NERC 10% band	Z α/2	σ	σ^2 or Variance	(WEIGHTING FACTOR)^2 * σ^2	(WEIGHTING FACTOR) * σ
1	RFC	0.586665	0.344176	5.69%	1.2816	4.44%	0.197%	0.000678215	0.026042563
1	SERC	0.167625	0.028098	4.66%	1.2816	3.63%	0.132%	3.71079E-05	0.006091625
1	MRO-US	0.245710	0.060373	4.56%	1.2816	3.56%	0.126%	7.63543E-05	0.008738095

Perfectly Correlated	4.09%
Perfectly independent	2.81%

----------->

0.96 Correlation

4.04%

Correlation	0.96

Table 4.2

Winter

Year		WEIGHTING FACTOR	(WEIGHTING FACTOR)^2	NERC 10% band	Z α/2	σ	σ^2 or Variance	(WEIGHTING FACTOR)^2 * σ^2	(WEIGHTING FACTOR) * σ
1	RFC	0.586665	0.344176	6.26%	1.2816	4.89%	0.239%	0.000821963	0.028669904
1	SERC	0.167625	0.028098	4.61%	1.2816	3.60%	0.129%	3.63582E-05	0.006029778
1	MRO-US	0.245710	0.060373	3.32%	1.2816	2.59%	0.067%	4.05526E-05	0.006368092

Perfectly Correlated	4.11%
Perfectly independent	3.00%

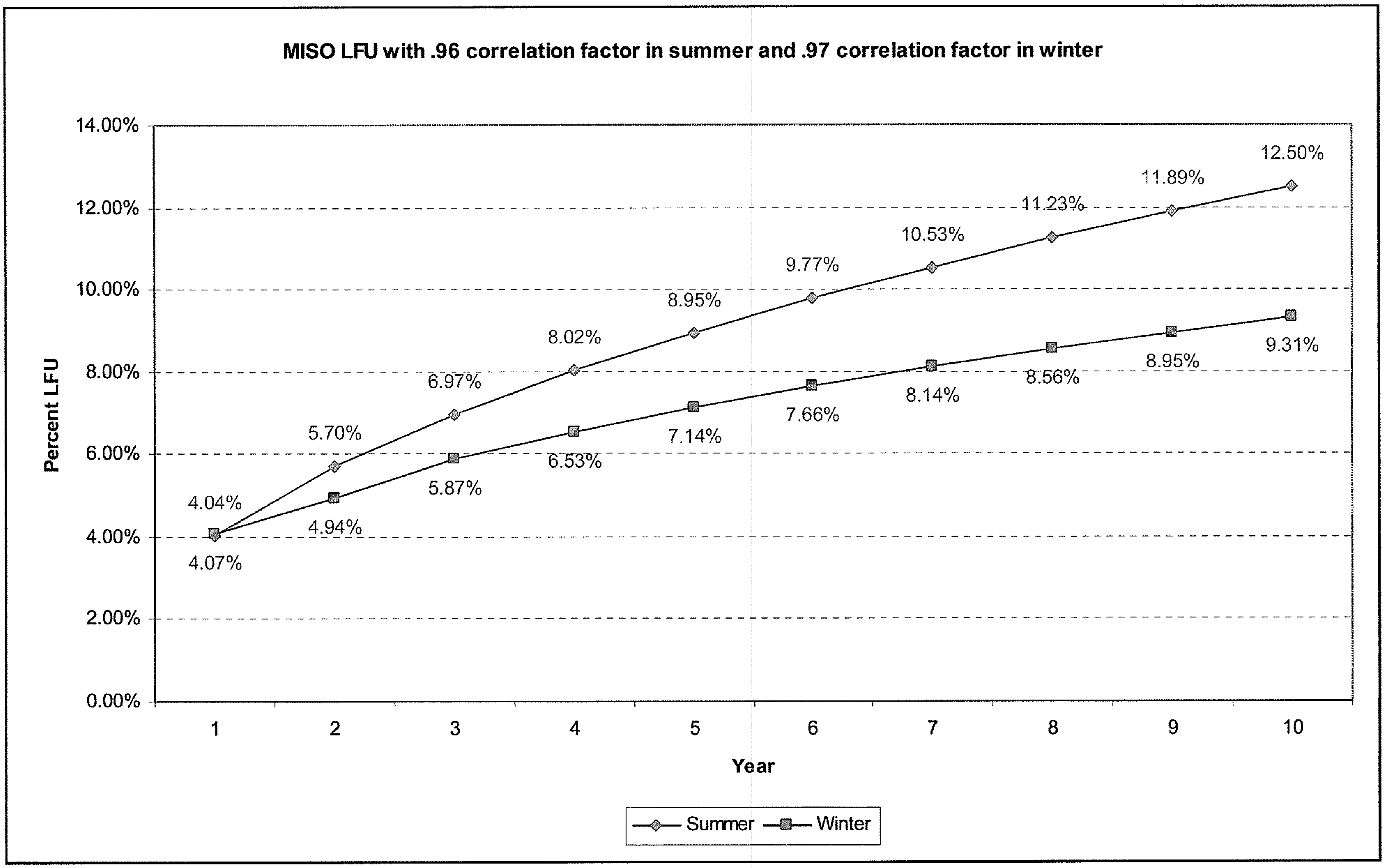
------------>

0.97 Correlation

4.08%

Correlation	0.97

Graph 5.1



MISO LFU with .96 correlation factor in summer and .97 correlation factor in winter
Percent LFU
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
1
2
3
4
5
6
7
8
9
10
Year
4.04%
5.70%
6.97%
8.02%
8.95%
9.77%
10.53%
11.23%
11.89%
12.50%
4.07%
4.94%
5.87%
6.53%
7.14%
7.66%
8.14%
8.56%
8.95%
9.31%
Summer
Winter

Appendix C EFORd, XEFORd, UCAP Metrics, and OMC Codes

Appendix Item C.1
EFORd, IGEN and UCAP Relationships and Findings for 2009

1) For each generator:

$IGEN\ (1 - XEFORd_{IGEN}) = UCAP$

Where: Installed Capacity = IGEN
Unforced Capacity = UCAP

2) For the total system results applied to an LSE with a 1,000 MW Non-coincident load:

$PRM_{IGENEFORd}$ = 12.69%, (2.35% diversity result highlighted value in Tables below)

System Average XEFORd = 6.514%, (6.75% from GADS data blended with assumed 0% XEFORd for Demand Resources = 6.514)

Forecast LSE Requirement = (Load + Load Modifying Resources) = 1,000 MW

IGEN Requirement= Forecast LSE Requirement * (1+$PRM_{IGENEFORd}$) = 1,000 * (1+0.1269) = 1,127 MW

UCAP Requirement = ICAP Requirement * (1 – System Average XEFORd), and substituting values gives:

UCAP Requirement = 1,127 * (1 – 0.06514) = 1,054 MW

3) By applying the following equation to define PRM_{UCAP} metric:

(1 – System Average XEFORd) (1+$PRM_{ICAPXEFORd}$) = (1+$PRM_{UCAPXEFORd}$)

$PRM_{ICAPXEFORd}$= 12.49%, (2.35% diversity result highlighted value in Tables below)

System Average XEFORd = 6.514%
Then (1 – System Average XEFORd) = 0.9349

And,

$0.9349\ (1+0.1249) = 1 + PRM_{UCAP}$
$PRM_{UCAPXEFORd} = 0.9349\ (1+0.1249) - 1$
$\mathbf{PRM_{UCAPXEFORd} = 0.0516 = 5.16\%}$

The total PRM is represented by the **XEFORd** driven component $\mathbf{PRM_{UCAPXEFORd}}$ **= 5.16%** plus the system wide average **Force Majeure** component adder for generators of **0.18%**. Therefore, the total

$\mathbf{PRM_{UCAPEFORd} = 5.16\ \% + 0.18\% = 5.35\%}$
0.18% is the 2.35% diversity result highlighted in Tables below

4) Amount of Capacity Required for the Modeled Market Load

Coincident Load x 115.40% = 110,625 x 1.1540 = 127,661 MW_{IGEN}

And within round off error:

Non-coincident Load x 112.69% = 113,287 x 1.1269 = 127,663 MW_{IGEN}

Table C1 - Summary of IGEN versus UCAP
At 2.35% diversity for total Model footprint:

	Non-coincident Load Based		Coincident Load Based
Basis of PRM:	PRM_{UCAP} (%)	$PRM:_{LSEIGEN}$ (%)	$PRM_{SYSIGEN}$ (%)
No congestion reference XEFORd $_{\text{Generation and BTM}}$	**4.61%**	**11.90%**	**14.59%**
With congestion XEFORd $_{\text{Generation and BTM}}$	**5.16%**	**12.49%**	**15.20%**
System average Generator Force Majeure adder	**0.18**	**0.20%**	**0.20%**
With congestion EFORd $_{\text{Generation and BTM}}$	**5.35%**	**12.69%**	**15.40%**
Model footprint Load	**123,227**	**123,227**	**120,331**
Model footprint Required Capacity	**129,819** $_{UCAP}$	**138,862** $_{IGEN}$	**138,862** $_{IGEN}$
No External Ties	**6.07%**	**13.46%**	**16.19%**

Table C2 - Summary of IGEN versus UCAP
At 2.35% diversity for the Midwest ISO Planning Reserve Zones (PRZ):

	Non-coincident Load Based		Coincident Load Based
Basis of PRM:	PRM_{UCAP} (%)	$PRM:_{LSEIGEN}$ (%)	$PRM_{SYSIGEN}$ (%)
No congestion reference XEFORd Generation and BTM	4.61%	11.90%	14.59%
With congestion XEFORd Generation and BTM	5.16%	12.49%	15.20%
System average Generator Force Majeure impact	0.18	0.20%	0.20%
With congestion EFORd Generation and BTM	5.35%	12.69%	15.40%
Midwest ISO Market PRZs	113,287	113,287	110,625
Midwest ISO Market PRZs Required Capacity	119,347 UCAP	127,661 IGEN	127,661 IGEN
No External Ties	6.07%	13.46%	16.19%

Table C3 - 2009 Compliance Summary for the Midwest ISO Market Planning Reserve Zones:
At 2.35% diversity and 15.40 $PRM_{SYSIGEN}$

	Non-coincident Load Based		Coincident Load Based
Basis of PRM:	PRM_{UCAP} (%)	$PRM:_{LSEIGEN}$ (%)	$PRM_{SYSIGEN}$ (%)
Total PRM EFORd (first column is applicable to Forecast LSE Requirement)	5.35%	12.69%	15.40%
Midwest ISO Market Zones Load	113,287	113,287	110,625
Midwest ISO Market Zones Required Capacity	119,347 UCAP	127,661 IGEN	127,661 IGEN

Appendix Item C.4
OMC Codes used in Midwest ISO

The term $XEFOR_d$ represents calculating the forced outage rate by excluding OMC outage causes when performing the calculation that would otherwise compute the $EFOR_d$. Currently, the Midwest ISO study utilizes 27 cause codes in its OMC set of outages and otherwise uses the NERC default set of 36 OMC cause codes . The 27 OMC Codes approved by stakeholders for use in the Midwest ISO LOLE study as listed in the BPM are shown in Table C4 below.

Table C4 - Outage Cause Codes included in the OMC set for Midwest ISO Studies

Code	Description	Midwest ISO and PJM OMC List
3600	Switchyard transformers and associated cooling systems - external	1
3611	Switchyard circuit breakers - external	1
3612	Switchyard system protection devices - external	1
3619	Other switchyard equipment - external	1
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)	1
3720	Transmission equipment at the 1st substation) (see code 9300 if applicable)	1
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)	1
9000	Flood	1
9010	Fire, not related to a specific component	1
9020	Lightning	1
9025	Geomagnetic disturbance	1
9030	Earthquake	1
9035	Hurricane	1
9036	Storms (ice, snow, etc)	1
9040	Other catastrophe	1
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels	1
9135	Lack of water (hydro)	1
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.	1
9250	Low Btu coal	1

9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)	1
9320	Other miscellaneous external problems	1
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated	1
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated	1
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated	1
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated	1
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)	1
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)	1
	Total	**27**

The accommodation of Force Majeure outage causes by using the EFORd metric as the input data to the GE MARS application is normal; however a sensitivity run with the $XEFOR_d$ metric can be done to examine the impact of the Force Majeure.

Appendix D RE Compliance Conformance Tables

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
R1 The Planning Coordinator shall perform and possess the documentation of a planned Resource Adequacy assessment. **R1.1** Be performed annually unless a document summarizing a review of system data that concludes that changes to system data used in the assessment do not warrant such a study is provided to the MRO. A study is warranted if changes have occurred that require revisions in any key assumptions such as generation mix and transmission limitations that are not covered by a sensitivity study. The planned Resource Adequacy assessment is to be conducted for Year One through Year Ten. Year One is defined as the year that begins with the upcoming annual peak season.	**R1** The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	Commitment is a prevailing requirement of Section 68 of Module E to the Midwest ISO Tariff.

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
R1.2 Be performed to meet a LOLP of no greater than 0.1 day in one (1) year which equals the sum of the LOLE for the integrated daily peak hours for each year. This shall be done for a minimum of 3 periods within the Year One through Year Ten (as defined in R1.1) to ensure meeting one (1) day in ten (10) years. These periods are Year One, a minimum of one year in years 2 through 5, and a minimum of one year in years 6 through 10. **R1.2.3** ~~Be performed for every day of each year throughout the period in R1.1.~~ ←Conflicts with 3-year choice in R1.2 Expected Unserved Energy may be performed as the method to meet R1.2 provided the results of such an assessment is compared with an LOLP analysis and the comparison is documented.	**R1.1** Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.2 points to satisfying the criteria by iteratively altering "the available capacity to each zone to ensure that the Midwest ISO system as a whole obtained a LOLE value of 1 day in 10 years or 0.1 days/year". This was all achieved with proper generator, transmission network representation, and load forecast data having been input to a GE MARS simulation. The GE MARS program gives the capability to perform full sequential monte-carlo simulation on multi-area basis. MARS calculates the annual LOLE by summing up the daily LOLP for the peak hour.

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
	R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	These demand side attributes were either subtracted from the load forecast or appropriately model as a resource in the simulation (see Appendix B, heading1). Since the value, for the ratio of resources to load, at the point of 1 day in10 reliability is the essential output sought; the amount of DCL or Interruptible Load does not significantly affect the total LOLE. Specific treatment was only necessary in the details of the LFU in Appendix B.
	R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).	The 15.4% reserve margin for 2009 is stated in the right column of Table 4. The report also states as a lower percent, the same required MW's of generation, but upon a higher sum of non-coincident LSE individual peak load forecasts (i.e. 12.69% upon the sum of non-coincident individual LSE peak load forecasts for 2009 equated to requiring the same MW's of generation as a 15.4% system wide reserve on the coincident peak). The 2.35% diversity for this shift is stated in Section 1 and developed in Section 3.2. Secondly, the resource capacity needed is stated in the lowest % metric as Unforced Capacity (UCAP) MW's. Table 5 shows all three percentage metrics and the associated un-bundled driving components. Also demand side resources are netted from the LSE load forecasts.
	R1.2 Be performed or verified separately for each of the following planning years:	
	R1.2.1 Perform an analysis for Year One. .	In Section 4, a full analysis was performed for year 2009, with the amount of reserve due to congestion itemized; resulting with a total reserve margin of 15.4%.

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
	R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	In Secton 5, a full analysis was performed for the year 2018, with the amount of reserve due congestion itemized, resulting with a total reserve margin of 17.0% (see Table 7). Also, analysis was performed for year 2013 without congestion which resulted in a 14.5% reserve margin, and then an estimated 1.3% was added for congestion in 2013, by interpolating the congestion adder between the fully analyzed years 2009 and 2018. Resulting in a 15.8% reserve margin for 2013. Years 2, 3, 4, 6, 7, 8, and 9 were calculated by interpolating years 2, 3, and 4 between 2009 and 2013. Years 6, 7, 8, and 9 were calculated by interpolating between years 2013 and 2018 (see summary on Table 7).
	R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year	The current 2009 study effort for the Midwest ISO market addressed all years 1 through 10.
R1.3 Include, at a minimum, documentation of how and why the following were/were not included in the analysis:	**R1.3** Include the following subject matter and documentation of its use:	
R1.2.1 Use loads developed from the expected 50:50 probability load forecast, **R1.2.2** Include load forecast uncertainty such as uncertainty due to load diversity, seasonal load variation, load variability due to other region economic forecasts or other factors. **R1.3.2** Load Characteristics **1.3.2.1** Load forecasts	**R1.3.1** Load forecast characteristics: • Median (50:50) forecast peak Load. • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible).	• Midwest ISO collects this information from our Market participants on an annual basis (Module E templates) • Midwest ISO includes LFU (Load Forecast Uncertainty) in this MARS analysis, which takes into account load diversity, seasonal load variation, load variability due to regional economic forecasts and other related factors. Additionally, LOLE WG and a separate LFU Task Team had inputs into the Midwest ISO's key assumption. LFU is addressed in Section 3.1.3, Table 5, and Appendix B. • The simulation accommodated hourly diversity (which captured

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
1.3.2.2 Load forecast uncertainty **1.3.2.3** Load diversity **1.3.2.4** Seasonal load variations **1.3.2.5** Load variability due to weather, regional economic forecasts, etc. **1.3.2.6** Daily demand modeling assumptions (firm, interruptible) **R2** On an annual basis, the Planning Coordinator shall document an assessment of its Resource Adequacy by comparing its load and resource capability for the ten year period in R1.1 expressed as a percentage of the 50:50 probability forecast peak load with the planning reserve margin benchmark in R1.4.	• Contractual arrangements concerning curtailable/Interruptible Demand.	seasonal and daily load diversity) by means of the nominal historical patterns provided from vendor data. This accounted for diversity of both external and internal load shapes. • In the simulation, demand side resources and small distributed generation are modeled as resource blocks. • Firm transactions flowing outside of the Midwest ISO were ignored in the simulation because the simulation is performed to determining the ratio of needed capacity to forecasted load in the Midwest ISO. Double counting of utilizing specific resources is a tracking process that is addressed for example in a seasonal assessment type of study. The Midwest ISO also has a capacity tracking tool (MECT) that accounts for how much of specific physical resources are assigned to specific parties or dedicated to non-market sales. Firm imports are quantified in **R1.3.2** (below).

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
R1.3.1 Resource availabilities **1.3.1.1** Historic resource performance and any projected changes **1.3.1.2** Seasonal resource ratings **1.3.1.3** Modeling assumptions of non-conventional resources such as wind and cogeneration **1.3.1.4** Energy limitations of hydroelectric units. **1.3.1.5** Merchant plant availabilities **1.3.1.6** Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area **1.3.1.7** Availability and deliverability of fuel **1.3.1.8** Common mode outages that effect resource adequacy **1.3.1.9** Other environmental or regulatory restrictions of resource availability **1.3.1.10** Available Demand-Side Management **1.3.1.11** Resource maintenance outage schedules **1.3.1.12** Sensitivity to resource outage rates and resource capabilities **1.3.1.13** Consider impacts of extreme weather/drought conditions	**R1.3.2** Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis	• All analysis was driven by the direct collection of generator outage rate history of the units in the Market. Class average data (Table 3) available from NERC was used for new units, units without an otherwise established history, and for modeled non-market units. • Maximum capacity ratings were varied seasonally. • Firm transactions into the Midwest ISO (including the MW's of capacity that may be located external to the Midwest ISO and depend on transmission service for delivery into the Midwest ISO) were used to determine the extent to which the available transmission tie capacity to the external system is used. The net result was used in the simulation (see Table 2). • Planned resources were included based on resources submitted by LSE's and status of units from the Midwest ISO queue. The simulation was targeted at seeking what level of capacity would achieve the 1 day in 10 reliability criteria. Additional capacity adjustments or removal of capacity from the simulation were then made to ensure that the Midwest ISO system as a whole obtained a LOLE value equal to the1 day in 10 years or 0.1 days/year. Iteratively fine tuning the capacity in the key zone(s) quantifies the required reserve % to meet the 1 day in 10 criteria. • Concurrently, all external zones were modeled with a ratio of capacity to load that provided them with 1 day in10 reliability as well. Thus the equivalents were neither represented as capacity rich or capacity deficient neighbors, but modeled as being compliant on a basis equal to the Midwest ISO..

Requirements under: **Standard RES-501-MRO-02** **Draft_1_v5_081204**	**Requirements under:** **Standard BAL-502-RFC-02** **12/4/2008**	**Response in:** **Midwest ISO 2009 LOLE Report** **(or reference to where accommodated)**
R1.3.3 Transmission limitations that prevent the delivery of generation reserves **1.3.3.1** Transmission maintenance outage schedules. **1.3.3.2** Transmission forced outage rates **1.3.3.3** Transmission availability for emergency considering firm commitments	**R1.3.3** Transmission limitations that prevent the delivery of generation reserves	Limitations to delivery from generators and to specific load areas were developed per detailed Steps outlined in Section 68.1.2 of Module E to the Tariff, and the Midwest ISO Business Practices. Transmission Limitations are discussed in Section 3.1, and quantitatively illustrated in Figure 3-1. Impacts of transmission limits 'congestion' upon the reserve margin are quantified in Tables 5 and 7.
	R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Future facilities were defined from the Midwest ISO Expansion Planning (MTEP) process which includes a data base of future planned upgrades to the system. Section 2.1 refers to the Model On Demand (MOD) process, which extracts the appropriate upgrades for a future specified time.
R1.3.5 Emergency assistance from other interconnected systems including multi-area assessment considering transmission limitations	**R1.3.4** Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	The Midwest ISO system is represented as multiple areas and areas external to the Midwest ISO were also modeled. Figure 3.1 quantifies the generation, load, and equivalent value for transmission between all modeled areas.

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
R1.3.4 Modeling assumptions for emergency operation procedures used during unexpected resource outages. **R1.3.6** Document and justify the inclusion of market resources not committed to serving load (uncommitted resources) within the planned Resource Adequacy Assessment analysis. **R1.4** Express the planning reserve as a percentage of the 50:50 probability forecast peak load (planning reserve margin). **R1.5** Ensure capacity resources located in another Planning Coordinator area and used in this assessment have been documented and such documentation has been provided to that Planning Coordinator.	**R1.4** Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	• Fuel was treated as an energy resource and unit capacity only affected if the historical EFORd outage data had embedded outages caused by fuel delivery.. • Common mode failure was only incorporated to the extent that GADS performance data captured such events. •The capacity of wind resources was assigned a value well below the name plate rating. • Outage rates (See Section 3.1.2 "Migration of GADS data into Study Model") were entered for the individual units within the footprint and those outages rates were then modeled within the MARS simulation. As can be seen in Section 4, Table 5 • Weather impacts are accounted for within the Load Forecast Uncertainty outlined in Appendix B • Emergency operating reserves are utilized as they become necessary thus allowing load to equal generation before a load shedding event is tallied. • All resources within the footprint were assumed to be utilized for reliability. • Environmental restrictions were treated as having emission limits over time; as such emissions were not accounted as impacting available capacity. This is similar to the treatment of fuel availability, which was treated as not affecting the availability of capacity.
	R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission Maintenance was not considered, however the Steps outlined in the Module E section of the Midwest ISO Tariff utilize a process to calculate the effective transmission tie ratings based on a first contingency basis (i.e. commonly referred to as an 'n-1' transfer capability basis). Also, by simulating generator outages with their EFORd ougate rate the statistical effect of transmission outages caused unit reductions were captured.

Requirements under: Standard RES-501-MRO-02 Draft_1_v5_081204	**Requirements under: Standard BAL-502-RFC-02 12/4/2008**	**Response in: Midwest ISO 2009 LOLE Report (or reference to where accommodated)**
	R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	Sections 2.1 and 2.2 describe the development of the combined representation of generators and the transmission grid through use of a data base, that are the foundation for input into the probabilistic treatment in Section 3.
R1.6 Document that all Load in the Planning Coordinator area is accounted for.	**R1.7** Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	Figure 2.2 illustrates the areas that are generally associated with the Midwest ISO market, as will as areas beyond the Market. The Midwest ISO proper represents about 1/3 of the total modeled load and generation facilities (quantified in Figure 3-1).
	R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	This documentation is completed within the Long Term Reliability Assessment completed annually and reported on the Midwest ISO site under the planning tab on the Regulatory and Economic Standards Page at: http://www.midwestiso.org/publish/Folder/81d7e_11b6e66e758_-7bad0a48324a
	R2.1 This documentation shall cover each of the years in Year One through ten.	Calculated reserve margins for all years are on Table 7
	R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The three analyzed years 2009, 2013, and 2018 have their values show in red font in Table 7
	R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One	• Executive Summary for Year One was posted 12/20/2008 • Full report draft to LOLE WG 3/13/2009 • Public posting pending as of 3/23/2009, expected posting by 4/1/2009.

REC footnotes:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

MRO footnotes:

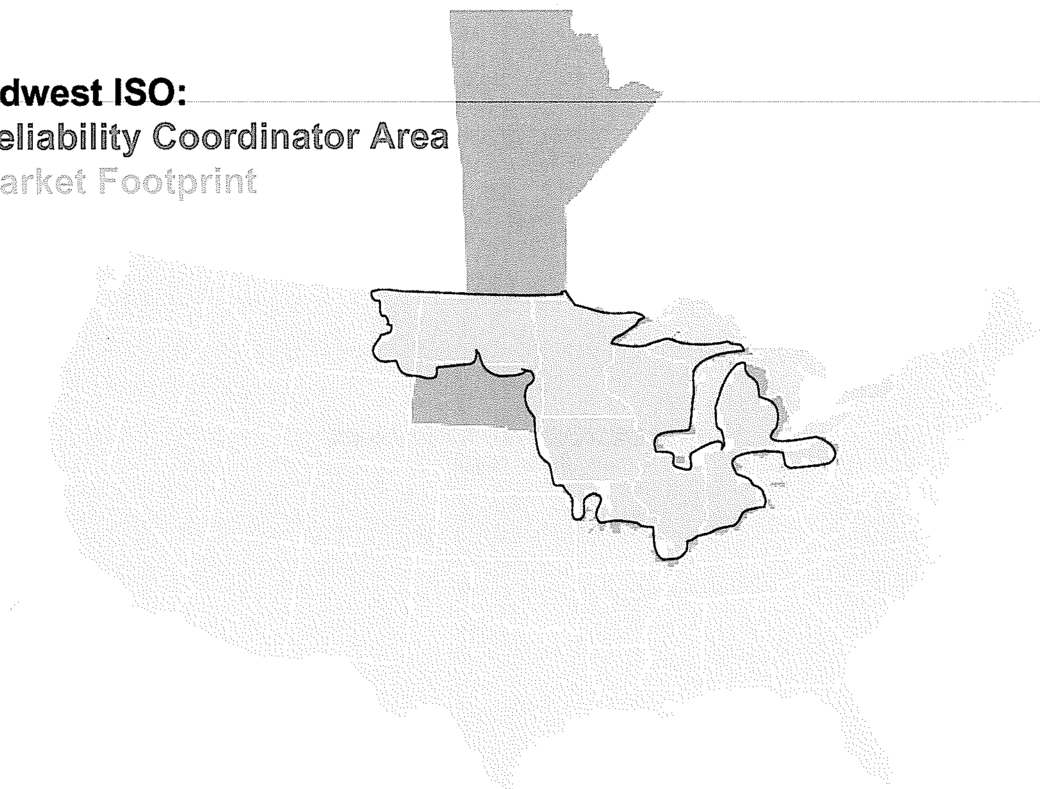
ATTACHMENT 2

Midwest ISO
Energizing the Heartland

Midwest Independent Transmission System Operator, Inc.

Planning Year 2010 LOLE Study Report

Midwest ISO:
Reliability Coordinator Area
Market Footprint



Midwest ISO Market Footprint And Balance of Reliability Coordinator Area

Regulatory and Economic Studies (RES) Department

Revision History

Reason for Revision	Revised by:	Date:
Initial Posting Document	--	2-10-10
Added Revision History Updated Table of Contents to reflected added page Updated Posting Date from "TBD" to "February 12, 2010" in Compliance Table Corrected "Effective External Tie Capacity (EETC)", to "external Effective Import Tie Capacity (EITC)" and years on Page 28.	M. Swanson	3-08-10

Table of Contents

1. Executive Summary

An unforced capacity reserve margin of 4.50% applied to LSE non-coincident peaks has been established for the planning year starting June 2010 and ending May 2011. This value was determined through the use of the GE Multi-Area Reliability Simulation (MARS) software for Loss of Load analysis. PROMOD IV® was used to perform a security constrained economic dispatch which provided the congestion-driven zonal definitions used within MARS. The analysis resulted with one uniform Planning Reserve Margin, applicable to the Midwest ISO Market footprint as a single Planning Reserve Zone.

The goal of a Loss of Load Expectation (LOLE) study is to determine a level of reserves that would result in the Midwest ISO system experiencing one loss of load event every ten years. This equates to a yearly probability for insufficient capacity of 0.1. As modeled within the GE MARS software, the system would achieve this reliability level when the amount of installed capacity available is 1.154 times that of the Midwest ISO system coincident peak.

Within Module E, individual Load Serving Entities (LSEs) maintain reserves based on their monthly peak load forecasts. These peak forecasts do not sum to the system coincident peak because they are reported based solely on the entity's own peak, which could occur at a different time than the system peak. To account for this diversity within the system, a reserve margin was calculated for application to individual LSE peaks utilizing a 3.00% diversity factor. This resulted in an individual LSE reserve level of 11.94%, reduced from what would otherwise be a 15.4% reserve without accounting for diversity. Taking into account average unit availability within the Midwest ISO system a forced outage rate of 6.644% was used to arrive at an unforced capacity margin of 4.5%. An example of applying the results to LSE load is shown in Section 3.3.

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group was much appreciated by the Midwest ISO staff involved throughout the process.

2. PROMOD IV® Zonal Analysis

Establishing zones driven by transmission congestion for this LOLE analysis was completed using the PROMOD IV® tool to realistically model the transmission system as it is planned throughout the 2010 – 2011 planning year. This phase of the process both identified zones on the basis of congestion on the transmission system, and quantified restrictions to transfer levels in or out of the zones. The pink boxes on the process map in Section 2.2.4 indicate the PROMOD IV® related activities.

Usage of the word "zone"

- In the context of this 2010 LOLE study report the lower case word "zone" is used extensively in reference to the congestion-driven Marginal Congestion Component (MCC) Zones derived and modeled in the study process. The Tariff has many definitions with modifiers preceding the word Zone. For example Transmission Pricing Zone. The fundamental "Zone" term in the Tariff best reflects the essence of zone as used in this report.

  1.714 Zone: A set of Buses in a geographic area as determined by the Transmission Provider.

- The GE Multi-Area Reliability Simulation (MARS) uses the term area. Therefore, narrative may transition to the 'area' term when needed to describe certain detailed steps in the LOLE analysis.
- Three 'planning areas' (i.e. East, West, and Central) had been identified, before the current Resource Adequacy Requirements in Module E, as a construct for expansion planning study groups. Certain planning efforts continue to use those areas as a means to segregate sub-regional expansion planning topics. These areas should not be confused with the congestion-driven MCC Zones determined through the zonal analysis outlined in this report.

2.1. Construction of PROMOD IV® Model

Load and generating unit data was first imported from PowerBase for utilization in the PROMOD IV® zonal analysis. PowerBase is a commercially available database which is regularly updated by Midwest ISO staff to include Module E submissions such that member-reported load forecasts can be incorporated into studies. The power flow case used was the 2010 Summer Peak Pass 3 model from the 2009 MISO Series Models. Finally, an EVENT file was created which is used to specify summer and winter line ratings, to designate critical lines for which flows must be monitored and to define potential line-failure or contingency states. The EVENT file information was vetted through the Loss of Load Expectation Working Group (LOLEWG) as well as participants of the Midwest ISO Top Congested Flowgate Study to ensure that all stakeholders had a chance to offer feedback on its contents. The entire Eastern Interconnect was modeled during the PROMOD IV® analysis with non-member systems utilizing the default data from PowerBase and Florida modeled as a fixed transaction due to model limitations. The following sections outline the steps taken to construct the inputs to the PROMOD IV® software.

2.1.1. Updates to PowerBase

The PowerBase database used was originally developed for Midwest ISO Transmission Expansion Plan 2009 (MTEP 09). The demand and energy forecast information was updated using the most recent data submitted by Load Serving Entities through the Module E process.

The MTEP 09 Report can be found at the following link:

http://www.midwestmarket.org/publish/Folder/254927_1254c287a0c_-7e5f0a48324a?rev=1

2.1.2. Basic PROMOD IV® PowerBase Modeling Assumptions

All nuclear units that were set to retire within the study period (2010-2019) were assumed to be re-licensed and operational. Minimum capacities of coal units were changed in the following manner: Sub-critical coal to 25%, super critical coal to 40%. Supercritical units were identified from the Global Energy Data.
Coal and nuclear units were the only type to have a must run status. The hourly profiles for wind units were obtained from the National Renewable Energy Laboratory (NREL), Department of Energy (DOE) stemming from the Eastern Wind Integration and Transmission Study (EWITS). Further description of this data can be found in Section 9.1.3 of the MTEP09. Hydro electric units were represented in two groups, as a fixed pattern run-of-river, and as energy-limited that could respond to unit commitment.

2.1.3. Create power flow case from Model on Demand (MOD)

The power flow case used for the 2010 planning year is the 2010 Summer Peak Pass 3 of the 2009 MISO Series Models. These collaborative models are developed using projects from the MOD database as well as the Multi-Regional Modeling Working Group 2008 models for external areas. The 2010 Summer Peak case has an effective date of July 15, 2010.

2.1.4. Event file

In PROMOD IV®, the EVENT file is used to specify summer and winter line ratings, to designate critical lines for which flows must be monitored and to define potential line-failure or contingency states. A "base case" transmission configuration, with no outages at any lines or buses, is part of this data set.

In the events data, the user can specify single or multiple line outages and can monitor simultaneous outages in the system. Each line is matched with an outage state to analyze its impact on the system. While multiple line and outage pairs may be monitored simultaneously, the only restriction is that the user cannot define an outage state which removes every line at a generator bus. Although the program is able to monitor multiple line outages at a bus, there must be at least one line available to distribute power from a generator bus. A bus may not be isolated. There are a finite number of events that can be modeled in the EVENT file.

The original primary source of data for the EVENT file is the MISO Book of Flowgates. Over time, the Midwest ISO has updated EVENT files with the most recent information available. The EVENT file information for the 2010 Planning Year was updated using information from LOLEWG and the Midwest ISO Top Congested Flowgate Study. All information was updated and verified before PROMOD was run.

Transmission maintenance schedules were not included in the PROMOD IV® analysis of the transmission system due to the limited availability of reliable maintenance schedules and minimal impact to the results of the analysis.

2.1.5. Pool Definition

A pool is an area composed of a set of companies inside which all generators are dispatched together to meet the total pool load. Normally pools represent an energy market, like MISO or PJM. The study footprint was broken into several pools based on the structure of the energy market. In the MTEP 09 PROMOD IV® case, 11 pools were defined in the study footprint: MISO, PJM, SPP, MAPP, SERC, TVA, MHEB, NYISO, ISONE, IESO and Eastern Canada. Figure 2.1.5-1 shows all pools modeled in the study footprint.

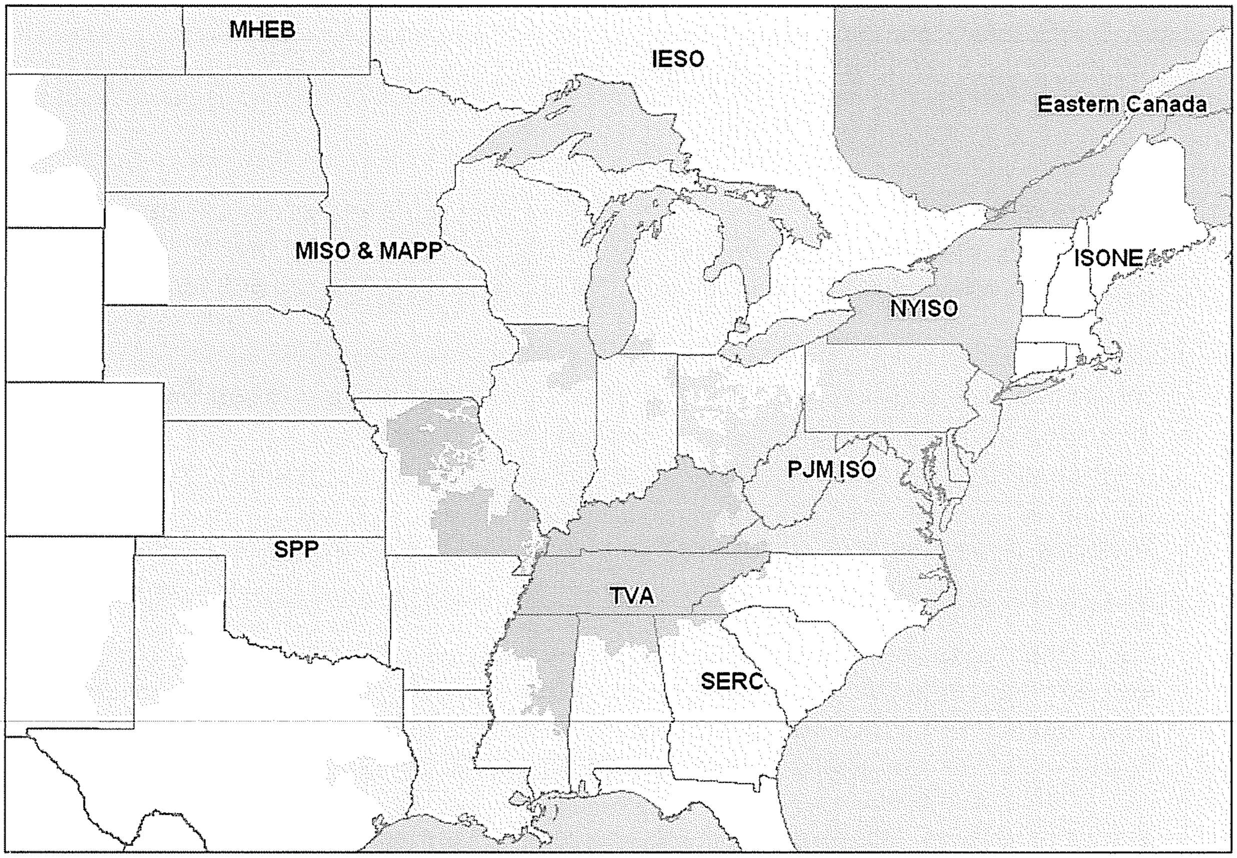


Figure 2.1.5-1: Pools in PROMOD IV Case

2.1.6. Hurdle Rates

Hurdle rates influence the capability of a pool to obtain support or sell energy to other pools. If two pools want to exchange energy, the difference of dispatch costs between the buying pool and selling pool must be greater than the hurdle rate between them.

PROMOD IV® performs the security constrained unit commitment and economic dispatch. Its solution includes two steps. The first step is unit commitment, and the second step is economic dispatch. For each step, the user can define its own hurdle rate. The hurdle rate defined for the unit commitment step is called the commitment hurdle rate, and the hurdle rate defined for the economic dispatch step is called the dispatch hurdle rate.

Normally, users will set the commitment hurdle rate to be more expensive than the dispatch hurdle rate such that the pool units will be dispatched against the pool load first in order to get the commitment order right and then allow pool interchange during the final dispatch via the dispatch hurdle rate.

There is no standard way to define the hurdle rates. Normally, hurdle rates are determined based on the filed transmission through-and-out rates, plus a market inefficiency adder.

In this study, the commitment hurdle rates are set at 10 $/MWH between all pools. The exception was MISO to MH, where we set the commitment hurdle rate set at 0 $/MWH. While MH is not a Midwest ISO Transmission Owner, an agreement between MH and the Midwest ISO, is more appropriately represented with a zero hurtle rate versus other entities outside the Midwest ISO. The dispatch hurdle rates between pools are shown in Table 1.

Table 1: Hurdle Rates

	Dispatch Hurdle Rate ($/MWH) Peak/Off-Peak										
To->	PJM	MISO	TVA	MAPP	SPP	SERC	E-CAN	IMO	ISONE	MHEB	NYISO
From											
PJM	*	2.5/2.5	4.8/4.8	4.8/4.8	N/A	4.8/4.8	N/A	N/A	N/A	N/A	7/7
MISO	2.5/2.5	*	7.6/5.4	7.6/5.4	7.6/5.4	7.6/5.4	N/A	7.6/5.4	N/A	0/0	N/A
TVA	6.5/4.5	8.3/8.3	*	N/A	8.3/8.3	8.4/5.7	N/A	N/A	N/A	N/A	N/A
MAPP	4.3/3.7	4.3/3.7	N/A	*	N/A	N/A	N/A	N/A	N/A	6.5/4.5	N/A
SPP	N/A	5.1/5.1	5.1/5.1	5.1/5.1	*	5.1/5.1	N/A	N/A	N/A	N/A	N/A
SERC	6.5/4.5	8.3/8.3	6.8/5.0	N/A	8.3/8.3	*	N/A	N/A	N/A	N/A	N/A
E-CAN	N/A	N/A	N/A	N/A	N/A	N/A	*	N/A	5/5	N/A	5/5
IMO	N/A	10.5/8.5	N/A	N/A	N/A	N/A	N/A	*	N/A	10.5/8.5	6.5/4.5
ISONE	N/A	N/A	N/A	N/A	N/A	N/A	5/5	N/A	*	N/A	5/5
MHEB	N/A	0/0	N/A	11.6/7.3	N/A	N/A	N/A	11.4/7.1	N/A	*	N/A
NYISO	5/5	N/A	N/A	N/A	N/A	N/A	5/5	7/5	5/5	N/A	*

2.1.7. Losses

Load in PROMOD IV® is equivalent to the actual load plus losses as included in the 50/50 LSE forecasts. In this study, PROMOD IV® does not calculate losses, but does calculate the marginal loss component of the Locational Marginal Prices (LMPs) in an approximation method. PROMOD IV® is capable of calculating losses using a more detailed method; however this option is not used due to run time considerations.

2.1.8. Monte Carlo Outage and Auto Maintenance

For the 2010 Planning Year Study, a single draw outage library was created for use in determining zones. However, forced outages were ignored in the PROMOD IV® run that determined import and export limits of the defined zones.

PROMOD IV® generates a maintenance schedule which optimizes maintenance to minimize loss of load events. After a maintenance schedule is developed, the same schedule is maintained for all subsequent PROMOD IV® simulations.

2.2. Analysis of System

A security constrained economic dispatch (SCED) simulation was run yielding Locational Marginal Prices (LMPs) for the various load buses which were representative of the cost for energy throughout the simulated period. These LMP values contain a component representative of the cost of congestion to that bus known as Marginal Congestion Component (MCC). These MCC values can either be positive or negative to indicate if there is a shortage or surplus of generation. Trapped generation around a bus is indicated by negative MCC values and a scarcity of generation around a bus is represented by positive MCC values. The MCC metric is available in PROMOD IV® for all modeled buses. Given that there was a plethora of buses modeled within the PROMOD IV® analysis it was imperative that selection criteria be utilized to narrow down the results. This study examined the most positive and most negative MCC values present on the system during peak conditions. These positive and negative MCC values were then grouped with surrounding buses of similar values to form the zones to be utilized in the LOLE study. This bus-based information affords the ability to quantify the load and generation in each zone, as needed in the GE MARS application going forward.

2.2.1. Selection of Buses for Contour Maps

PROMOD IV® can calculate hourly LMP components for selected buses. However, it is not feasible to analyze this data for all buses in the system. This would result in nearly 500 million (8,760 hours x 56,711 buses) MCC values. Therefore, a smaller selection of buses from hourly output was utilized for analysis and contour map definition. The respective contour maps for 2010, 2014 and 2019 are shown on Figure 4.2.2-1, Figure 5.1.2-1 and Figure 5.1.3-1.

For a bus to be selected, it was first required that a latitude and longitude was available for plotting purposes and be in or near the study region. Then generator buses (929) and buses greater than 200kV (935) were selected. Duplicate buses (same latitude and longitude) were eliminated. For the 2010 Planning Year Study, 1,556 unique buses were selected.

2.2.2. Formation of Candidate Zones

While the GE MARS model examines loss of load expectation on an hourly basis, transmission limits may only be set monthly. The fact that the GE MARS model utilizes a zonal transmission system or "ball and stick" model must also be taken into account when formulating zones. Due to these limitations a certain subset of the congestion observed during the PROMOD IV® analysis must be observed to arrive at zonal definitions which can then be used to derive monthly limits for input into the GE MARS model. The Marginal Congestion Component (MCC) value of the Locational Marginal Price (LMP) is used to identify how each buss in the transmission system is impacted by congestion hourly. The smallest time frame to reflect the congestion metrics into the GE MARS model would therefore be a particular hour, such as the peak load hour. For a single congested hour the Marginal Congestion Component for each buss would fall into one of three categories:

1. Be among the 30,000 most Positive MCC values (Red)
2. Be among the 30,000 most Negative MCC values (Blue)
3. Not among either of the above and defined as in the Neutral zone (Yellow)

However, rather than model the specific congestion on the transmission system for one hour, the goal for the LOLE model is to create a more broad or diverse representation of congestion that is applicable to a key reliability significant period of time, such as the peak hours of the peak load week. Conflicts arise as one attempts to represent long periods of time, such as a year or several months, because a unique MCC sign is not sustained for many busses. The requirement for a bus to be called Positive (RED) or Negative (BLUE) is for it to have experienced (over the hours in the shorter time period) only positive or negative MCC values with zero MCC values not affecting this analysis. Busses not represented in the 30, 000 most negative or 30,000 most positive sets of MCC values in the time period are not considered for zonal identification. In order to derive the most value from the PROMOD IV® simulations the time frame used for analysis must minimize the number of busses which experience both Positive and Negative MCC values. The end result is that busses are characterized as being consistently or persistently either positive or negative for the given time period. Thus, the metrics are determined using as many hours as possible. The surviving busses with their dominant MCC sign, are the basis for defining the candidate zones based on congestion during the most critical reliability timeframes. See Appendix E Congestion Based Zones, for a more detailed discussion of how zones are determined.

2.2.3. Zonal Filtering Criteria

At this stage of the study, candidate zones are evaluated to determine if they contained either 2000 MW of load or 2000 MW of generation. If a candidate zone did not meet the 2000 MW threshold, it was merged into the appropriate adjacent zone. A breakdown of the zones established through this process can be seen in Figure 2.2 2010 GE MARS Modeled Zones. The precursor geographically output information utilized to draw the refined Figure 2.2 is shown on Figure 4.2.2-1 in Section 4.2.1 Congestion Impact. Guidelines for merging smaller sized different colored areas into a larger composite area are set out in the Tariff and Business Practice documents. Zones 1, 2, 3, 4 and 5 were found to be of sufficient size to account for the load and generation within them, and calculate their Effective Import Transmission Capability or Effective Export Transmission Capability.

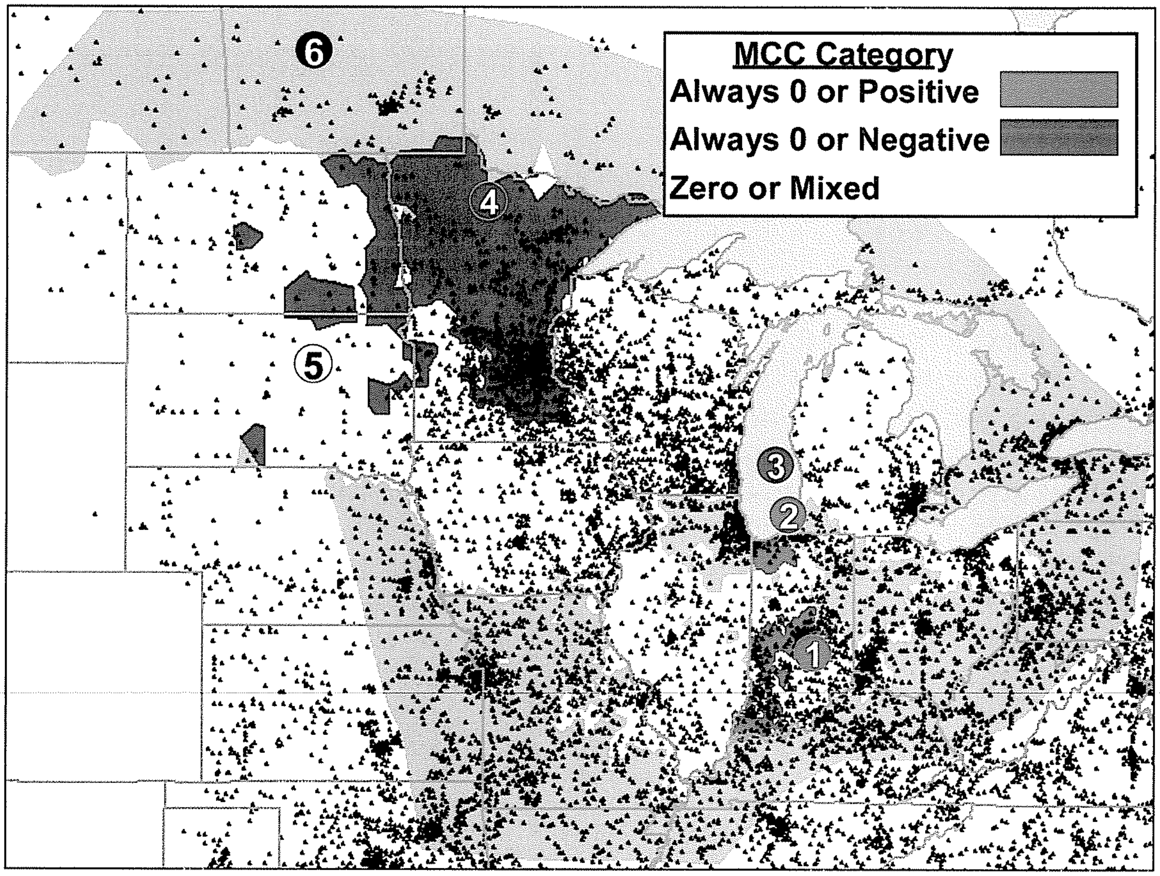


Figure 2.2 2010 GE MARS Modeled Zones

2.2.4. Transfer Analysis

The common red or blue clusters viewed in Figure 4.2.2-1 for the year 2010, Figure 5.1.2-1 for the year 2014, and Figure 5.1.3-1 for the year 2019 are precursors to candidate zones. After same sign (same color) clusters were evaluated or merged into final zones as in Figure 2.2, PROMOD IV® was used to determine the transfer limits between zones. The prices of generation in each zone were artificially adjusted to encourage power imports into generation deficient zones (red as seen in Figure 2.2) and exports from generation rich zones (blue as seen in Figure 2.2). This was done by setting the price of generation to be high in generation deficient zones, and the price of generation to be low in generation rich zones. The hourly zone interfaces flows were then evaluated to determine monthly limits for input into GE-MARS. The monthly limit was equal to the average of the interface flows at time of daily peak. For example, the January limit was the average of 31 flows at daily peak values.

2.2.5 Load Deliverability Analysis

After the zones are identified and the transfers are established between those zones an analysis must be performed to determine if the import limited zones (red zones in Figure 2.2 and Figure 2.2.6-1 in Section 3.1) have enough combination of resources and import capability to maintain an LOLE of 1 day in 10 years. If these zones do have enough Effective Import Transmission Capability (EITC) to maintain 1 day in 10 years then they are set at the same level of reliability as the rest of the system and can share the same Planning Reserve Margin without the need for additional short term precautions being taken. This testing of the red (i.e. positive MCC) zones is accomplished at the lavender diamond shaped activity shown on the right side of the Process Map in Section 2.2.6.

For the 2010/11 Planning Year two zones were found to be import constrained (Zones 1 and 2 in Figure 2.2) and required a load deliverability analysis to be performed. Along with the resources internal to Zones 1 and 2, the 6,083 and 981 MW level of EITC was found to be sufficient import capability to maintain 1 day in 10 years LOLE and therefore no additional precautions were recommended for Zones 1 and 2 at this time.

2.2.6. Process Map

The process map below illustrates the LOLE study data flow.

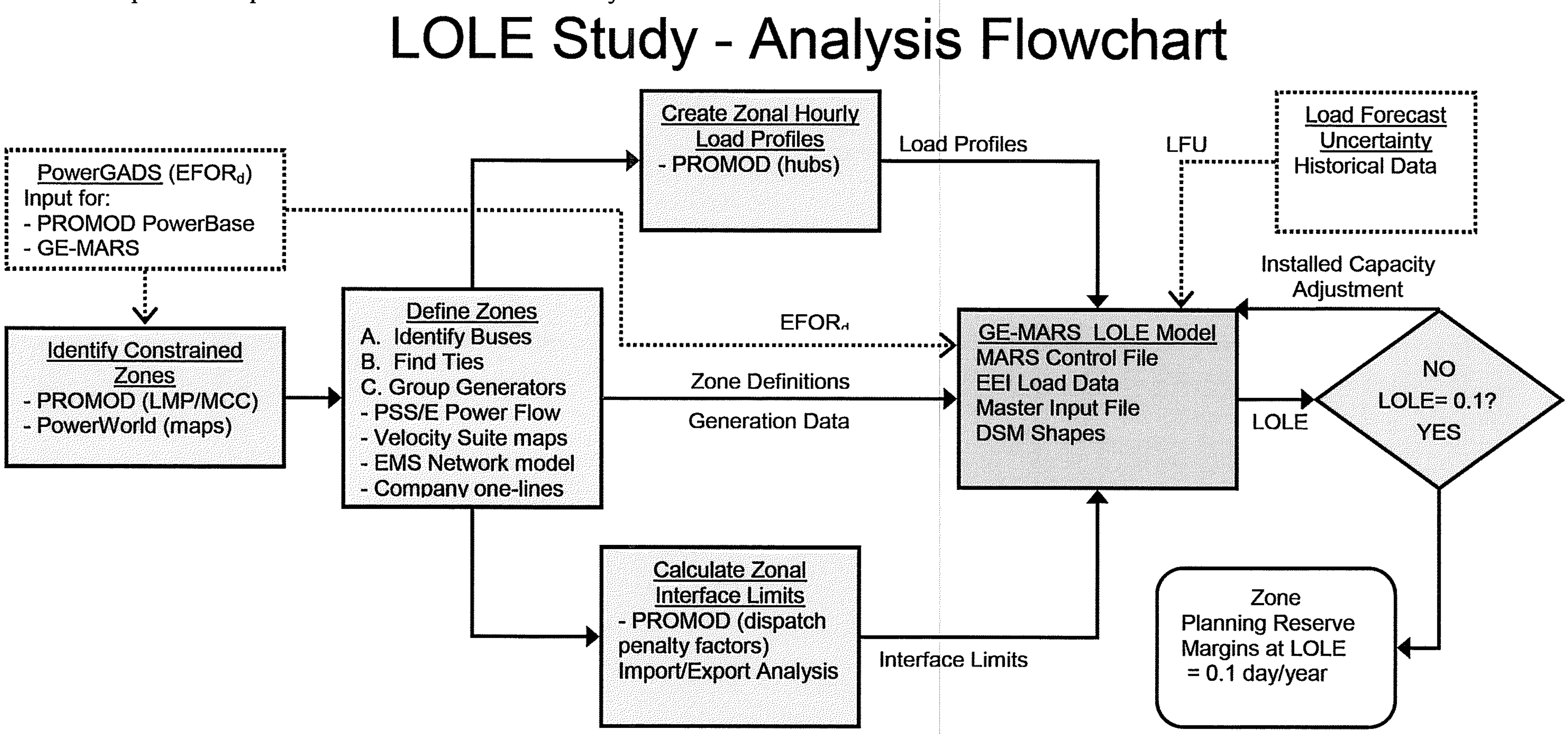


Figure 2.3: LOLE Study Analysis Flowchart

3. GE MARS Analysis

Utilizing the zones derived from the PROMOD IV® analysis, a MARS model was constructed using load, transmission and generation data from PROMOD IV® PowerBase incorporating unit outage statistics derived from Generating Availability Data System (GADS) reporting through the Midwest ISO's PowerGADS software. The **blue box** on the process map in Section 2.2.4 indicates the GE MARS activity.

3.1. Construction of GE MARS Model

The PROMOD IV® tool was used to group the buses as specified in Section 0 and output a single hourly load profile for each zone which included all hours within the period under scrutiny. These load profiles and zonal definitions were placed in the MARS Model where the transfer limits, also determined from the PROMOD IV® analysis, were applied. The generating units for each zone were also imported from the PROMOD IV® model; however, Forced Outage Rates (FOR) were updated with available GADS data. Each generator within a zone is assumed to be deliverable to all load within that zone. Since prices are high during peak load events and all generators are called on to serve load all resources within the footprint were assumed to be utilized for reliability regardless of load serving obligations. The inputs garnered from the PROMOD IV® analysis are represented in Figure 2.2.6-1 as they were input to the GE MARS model.

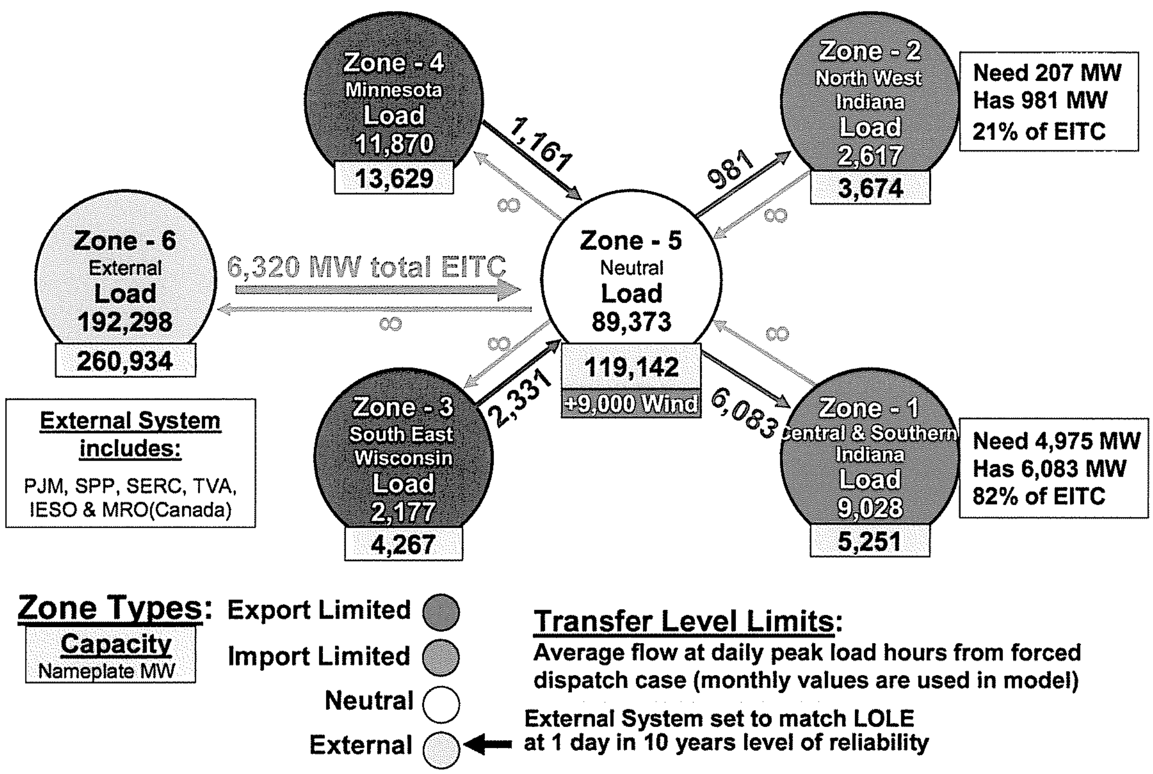


Figure 2.2.6-1: Zones and Parameters Modeled in 2010 GE MARS

Zones 1 and 2 utilized less than 90% of their total Effective Import Tie Capability (EITC) in order to maintain a 1 day in 10 year LOLE. Since the Zones meet this criterion no further analysis was performed on Zones 1 and 2 which were merged into the neutral Zone 5. The merged Zones 1, 2, and 5 are illustrated in Figure 2.2.4-2 and the external EETC is also quantified at 6,320 MW as determined from the calculation in Table 2. Zones 1 through 5 include all load within the Midwest ISO Planning Authority footprint.

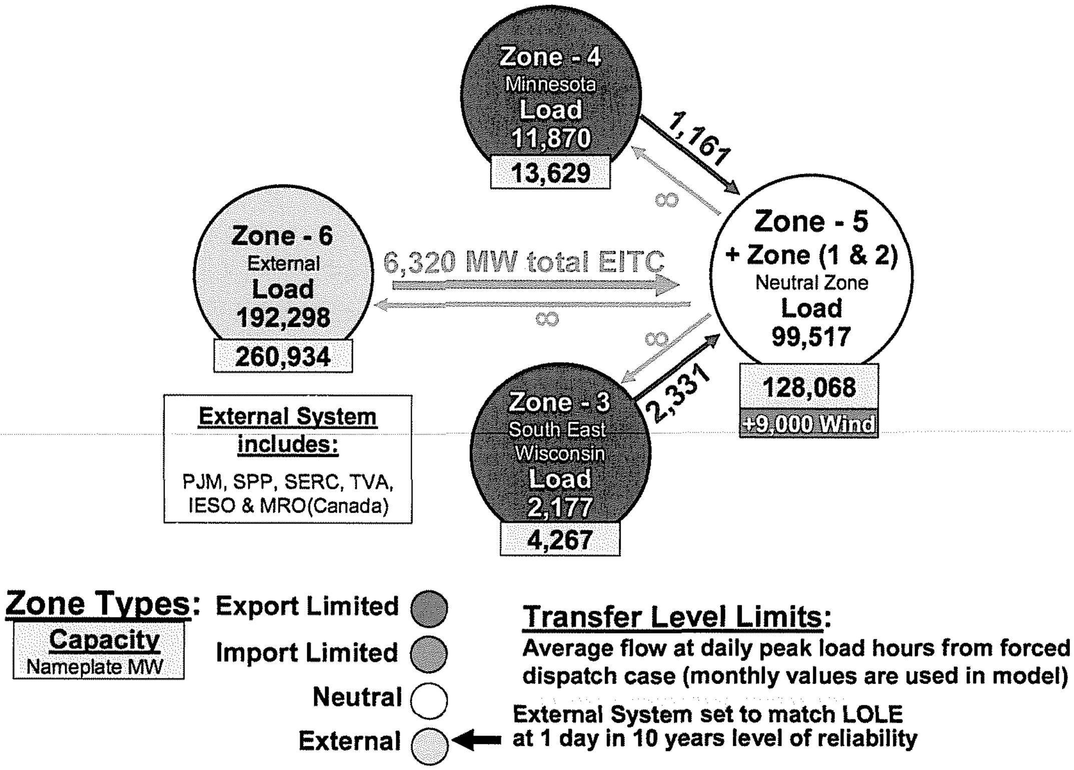


Figure 2.2.6-2: Zones and Parameters Modeled in 2010 GE MARS

Direct Control Load management and Interruptible Demand are included within the MARS model as load modifiers that can be utilized without incurring a loss of load event. In order to be included in the MARS model all Load Modifying Resources must first meet registration requirements through Module E. These requirements include, at a minimum: a shutdown time less than 12 hours, a maximum number of interruptions during the summer season greater than 5 and the ability to maintain interruption for 4 hours. Emergency Operating Procedures were also included within the model and were available for utilization without incurring a loss of load event.

3.1.1. Modeled External System Ties

In order to determine an appropriate level of support the external systems were held to the same reliability level as the internal system and an external tie capacity was derived. Historical total transmission flows and contractual flows were observed to obtain an applicable external support level. The 6,320 MW value for the external Effective Import Tie Capability (EITC) is shown in Figure 2.2.6-1. This value was determined as follows:

Table 2: External EITC Calculations

Maximum transmission import flow from Market Externals 8/1/2007	=	11,791 MW
Less transmission capability needed to serve 2007 Summer firm deliveries into Market	=	5,471 MW
Available transmission to import into Market	=	6,320 MW

Specific contractual capacity exports were not considered during this analysis although support to external entities was allowed.

3.1.2. Migration of Resource Characteristic into Study Model

The Generating Availability Data System (GADS) provides a standardized means to collect outage information on generators. This system was used to collect data for units within the Midwest ISO for the period of July 2006 through June 2009. This historical data was then used to update the Forced Outage Rates (FOR) and seasonal maximum capacities for each specific unit within the footprint that were imported to the GE MARS model from the PROMOD IV® PowerBase model. If a given unit did not have outage statistics, the Forced Outage Rate was not updated and the original class average FOR from the PROMOD IV® PowerBase model was utilized. Planned outage information was also incorporated from PROMOD IV® PowerBase with the necessary maintenance time input and the MARS program allowed to optimize the scheduling of maintenance for units without specific maintenance schedules. Any retirements listed in the database were incorporated into the MARS model, but no additional retirements were assumed for the study period.

The PROMOD IV® PowerBase is updated to incorporate all units within the Midwest ISO Interconnection Queue which have a Signed Interconnection Agreement. These updated are imported to the MARS model with the unit information and all planned additions within the database are included.

Energy limitations for hydro resources and other energy limited resources are also imported from PROMOD IV® PowerBase.

Forced outage rates utilized in this study were adjusted to exclude certain outage types, deemed as outside of management control, and account for the time when a unit was in demand as outlined in Appendix B EFORd, XEFORd, UCAP Metrics. These adjustments to the forced outage rates yielded an Effective Forced Outage Rate Demand (EFORd) that excluded certain outages which is known as XEFORd. While the EFORd values were utilized in the MARS simulations in order to capture all possible outages of generation the XEFORd values were utilized in Planning Reserve Margin calculations after the simulation was run as seen in Section 3.2. A listing of the class average forced outage rates experienced within the Midwest ISO is available here:

http://www.midwestmarket.org/publish/Document/2c2ca5_12511ba6cdc_-7e290a48324a?rev=1

Generator Forced Outage Rate definitions:

- **Equivalent Forced Outage Rate Demand (EFORd)**: A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.
- **XEFORd**: Same meaning as EFORd, but calculated by excluding causes of outages that are Outside Management Control (OMC). For example loss of transmission outlet lines are considered as OMC relative to a units operation.

The OMC codes excluded by the Midwest ISO are itemized in Appendix A Load Forecast Uncertainty (LFU) Final Report.

3.1.3. Load Forecast Uncertainty (LFU)

At the recommendation of the LFU Task Team this study utilized the same NERC Bandwidths Variance Calculation as the 2009 LOLE Study in order to determine a Load Forecast Uncertainty value. This method was recommended based on its historical use, its vetting through various groups and due to the updated NERC Bandwidths being unavailable at the time of the LOLE Study.

The majority of analysis performed by the task team converged on a similar number in the 4.00% standard deviation range. Using the NERC Bandwidths Variance Calculation a sigma value of 4.04% for the summer and 4.08% in the winter was determined. This load forecast uncertainty was applied to the entire footprint and more information (including the LFU values used as input to the MARS model) on LFU can be found in Appendix A Load Forecast Uncertainty (LFU) Final Report.

3.1.4. Wind Generation

Wind generation was not modeled in the GE MARS runs for the determination of PRM, because other analysis is done to determine the equivalent UCAP capacity for wind. As UCAP capacity is "perfect" capacity with no forced outage rate, the impact of including wind would have the same effect as the capacity adjustments which are made to achieve a 1 day in 10 LOLE solution. Therefore no specific treatment of wind is needed for determining the PRM, since there is no need to assign the final adjusted block of capacity to any particular resource type. The capacity rating for the wind is discussed in Section 4.2 and Appendix E. That process handles the hourly wind generation pattern by subtracting it from the hourly load. Then the balance of the resources addresses the net load. Some background work is also shown in Appendix E where the wind generation was alternatively modeled as generator statistically available at various power levels. This is a standard model available in the GE MARS program. The shape for the availability was developed from historical performance of Midwest ISO wind generation during peak load times over the past five years. Simulated performance from 2003 and 2004 was also used in the establishment of availability.

3.2. Determination of Planning Reserve Margin

Once the base model with generation, load, and tie line capabilities was defined, a simulation was run to determine the Loss of Load Expectation (LOLE) value for the planning year. Capacity adjustments were then put in place to alter the available capacity in each zone to ensure that the probabilities for loss of load within the Midwest ISO system over each integrated peak hour for the planning period summed to 1 day in 10 years or 0.1 days/year. When the Midwest ISO system as a whole is at 0.1 days/year then all zones within the system will have a LOLE of 0.1 days/year or less. All external zones were modeled at the same level of reliability to ensure that they were not providing more support than would be statistically available. When capacity was appropriately adjusted in each LOLE zone to bring all systems to a 0.1 days/year LOLE value the ratio of capacity to coincident load in the Midwest ISO yielded a reserve margin of 15.4% of the 50/50 net internal demand forecast. This value is the planning reserve margin as applied to the Midwest ISO system coincident peak.

In order to account for the diversity within the system and yield a reserve margin applicable to individual Load Serving Entity (LSE) monthly peaks, as mandated by Module E, a diversity factor adjustment was necessary. Historical load data was available on a CPNode or Local Balancing Authority basis. Each LSE reports their load forecasts separated into one or more CPNodes. For the purpose of this analysis the Midwest ISO calculated historical peak month diversity factors for 2005 through 2009 by comparing the Midwest ISO system peak to the sum of the CPNode Peaks for each peak month. Below is the calculation and resulting diversity factors for 2005 through 2009.

$$Diversity\ Factor = 1 - \frac{MISO\ Coincident\ Peak}{\sum^{Month} CPNode\ Peaks}$$

Table 3: Historical Diversity Factors

Peak Month Diversity	
Month	**CPNode Diversity**
Aug-05	3.99%
Jul-06	2.94%
Aug-07	6.51%
Jul-08	6.29%
Jun-09	5.27%

The amount of diversity experienced in the Midwest ISO footprint since the start of the Energy Market in 2005 has ranged from 2.94% at its lowest in 2006 to a high of 6.51% in 2007. Because of the limited amount of historical data available to the Midwest ISO and the significant impact diversity factor has on the resulting Planning Reserve Margin the Midwest ISO sought feedback from stakeholders on how to account for diversity. In an attempt to quantify the risk associated with the variability of diversity, previous outputs from the LOLE model were used. By examining the contribution of Load Forecast Uncertainty to the Reserve Margin, an estimation for the effect of Diversity Uncertainty could be derived. Using this estimation, depending on input assumptions, it was determined that a Diversity Factor between 2.7% and 3.5% would not have a material impact on the Loss of Load Expectation. Taking into consideration the fact that diversity could not be accurately modeled in the allotted time and that diversity has a very significant impact on Reserve Margin, a diversity factor of 3.00% is used for the 2010/11 Planning Year. This value was applied to the coincident load used in the original reserve margin calculation to yield a non-coincident peak load from the system coincident peak. This increased load value was utilized to yield an 11.94% planning reserve margin as applied to individual LSE peaks.

The final step was determination of the planning reserve margin on an unforced capacity basis. The system wide average XEFORd for generation within the Midwest ISO Market was 6.83% which was computed from the historical data for generators that represented 99.4% of the modeled generation. A system average XEFORd was developed by applying a 6.83% XEFORd value to all 141,991 MW of Generation within the Model and a 0% XEFORd to the 4,053 MW of Demand Resources. This methodology resulted in a System Average XEFORd of 6.644% for use in an Unforced Capacity Reserve Margin. This outage rate was then applied to the capacity in the previous reserve margin ratios. This lower capacity value was then divided by the previously adjusted load value to arrive at a new planning reserve margin of 4.50% which must be served with unforced capacity. Unforced capacity for an individual unit is derived by applying a unit's XEFORd to its maximum capacity rating to arrive at a reliably provided MW value.

3.3. Example of Applying the Results

Table 4 utilizes the load values shown in Figure 2.2.6-1 within the GE MARS model and quantifies the various values relative to the resulting PRM's, coincident and non-coincident peak load, diversity, and the XEFORd forced outage rate. The usage of IGEN, UCAP, XEFORd, etc. are exemplified in Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes

Table 3: For the Midwest ISO Market Planning Reserve Zones at 3.00% peak load diversity, XEFORd=6.644% and 15.40% $PRM_{SYSIGEN}$

	Non-coincident Load Based		Coincident Load Based
Generator MW Basis:	**UCAP**	**IGEN**	**IGEN**
Total PRM $_{EFORd}$ (first column is applicable to Forecast LSE Requirement)	**4.50%**	**11.94%**	**15.40%**
Midwest ISO Market Zones Load	**114,205**	**114,205**	**110,779**
Midwest ISO Market Zones Required Capacity	**119,344 $_{UCAP}$**	**127,839 $_{IGEN}$**	**127,839 $_{IGEN}$**

4. Details of 2010 Results

4.1. Further Discussion of Findings

4.1.1. Monthly Distribution of Loss of Load Expectation

The accumulation of LOLE throughout the 2010 planning year reveals that 41% of the accrued annual LOLE is realized in the month of July with the balance of 59% occurring in August. Figure 4.1.1-1 illustrates the distributions for PY 2009 and PY 2010 along with the tracking of wind output metrics.

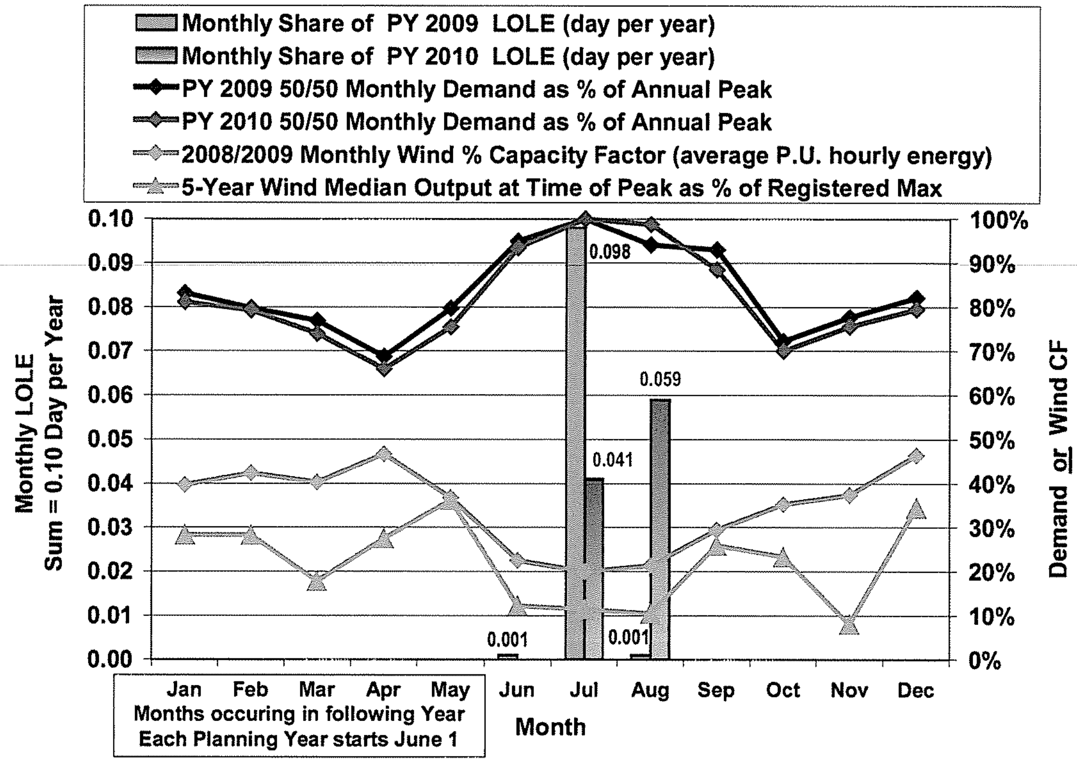


Figure 4.1.1-1 Monthly Distribution of Annual LOLE And System Wide Wind Output Metrics

4.1.2. Unforced Capacity (UCAP) Metric Review

Table 4 in Section 3.3 laid out the applicable Resource Adequacy Requirements (RAR) for the 2010 Planning Year; 15.40% $PRM_{SYSIGEN}$, 11.94% $PRM_{LSEIGEN}$, and 4.50% PRM_{UCAP}. The relationship and calculation among these values for a solved LOLE case, and how they relate to the system wide average XEFORd is explained by example in Appendix B EFORd, XEFORd, UCAP Metrics.

The metric of Unforced Capacity (UCAP) was utilized in this year's study in order to more equitably distribute the reserve requirement amongst a fleet of generation with varying outage rates. Through the use of Unforced Capacity all entities will utilize equivalent capacity to serve reserve margins.

4.2. Wind Penetration Sensitivity Analysis

A study was conducted to determine what equivalent fixed percent of the registered wind capacity on the system would be PRM neutral. The specific method and results are in Section 4.2.2. To gain familiarity with performance of the intermittent wind resource at peak load times, it is first helpful to review recent year's operations. Also, some discussion of Wind generation fleet performance versus the conventional dispatchable generation fleet performance is presented. While the illustrations are quantitative, only the calculations discussed in Section 4.2.2 drive the Wind Capacity Credit.

4.2.1. Operational Review of Wind and Dispatchable Generation

From review of wind output over 5 years at time of 8 highest daily peak loads in each year) the median amount of Registered Wind capacity MW that is realized as output at time of peak load is about 11.3%, with the current wind fleet in the Market (11.3% is median value of the column headed "Output % of Registered Max at Daily Peak Load", Appendix E Table E1). The 50/50 confidence level of expected daily commitment percentages for wind capacity and dispatchable capacity are illustrated in Figure 4.2-1. In other words half of the observations are above or below this point.

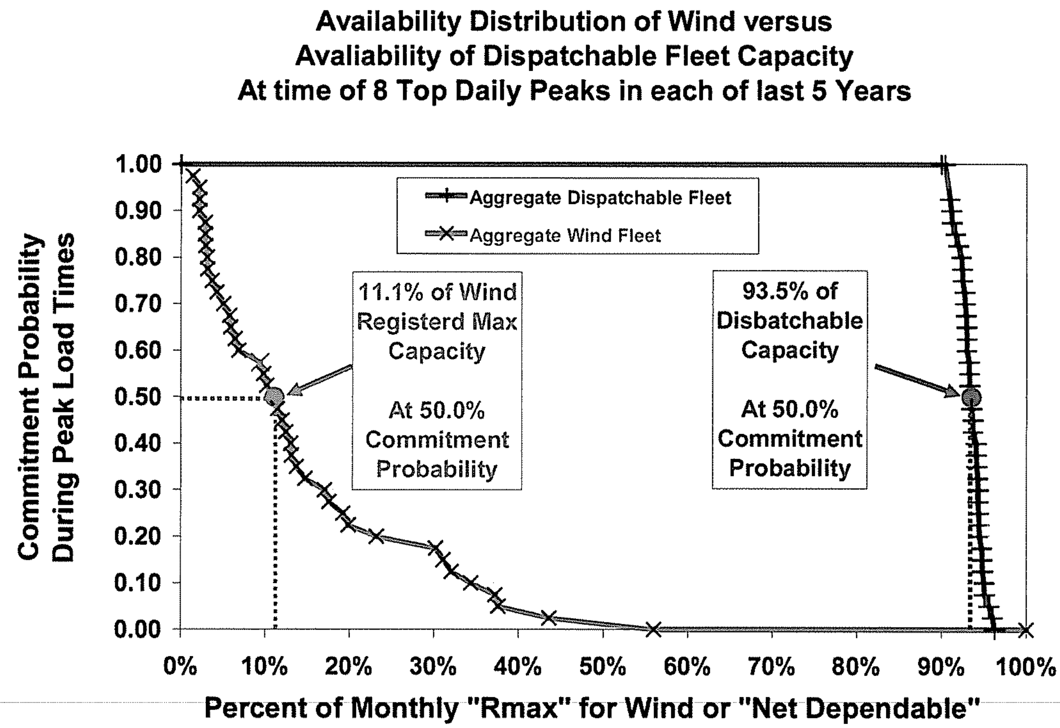


Figure 4.2-1 Wind Capacity Output at time of Daily Peaks

Figure 4.2-1 and Figure 4.2-2 are created from 40 values of the committable generation at the time of the 8 highest daily peak loads in each of the past 5 years. The wind data is taken from Market Settlements data, and the available dispatchable generation is taken form a special report that queried the GADS data at Midwest ISO. The curves performance is consistent with the GADS metric EFORd, but captured only for the particular 40 hours..

Two points along the X-axis of Figure 4.2-2 are of particular interest, because they indicate a comparison of wind and dispatchable capacity at a common bench mark. The 92.5% point noted on the Aggregate Dispatchable Fleet curve is essentially equal to the value (1 – dispatchable fleet's EFORd) = 92.90%, where a 7.1% EFORd is from GADS Data. While the performance plotted is reflective of including the Out of Management Control (OMC) outages and therefore more directly comparable to EFORd rather than XEFORd, the 93.5% point noted on Aggregate Dispatchable Fleet curve is essentially equal to the value (1 – dispatchable fleet's XEFORd) = (1 – 0.0638) = 93.6%, where the 6.38% XEFORd is from GADS data. Therefore, without accounting for wind penetration by means of doing an ELCC calculation, the first approximation to comparable treatment of the wind fleet to the distatchable fleet on the basis of availability would result in an upper Wind capacity credit of about 11.48%.

- Given the dispatchable fleet's UCAP being set at 93.6% of Net Dependable Capacity (NDC), occurs at coordinates (93.6%, 47.5%), and

- The comparable Wind resource fleet's UCAP would be at 11.48% of Registered Max Capacity, occurs at coordinates of same y-axis value as (11.5%, 47.5%)

Likewise the corresponding lower bound for the Wind Capacity Credit may be realized by:

- Starting on the X-axis at a point closest to the (1 – EFORd) = 92.5% point, which would be the coordinates (92.7%,72.5%), and
- The comparable availability for the Wind resource would be at the coordinates (4.3%,72.5%) for a capacity credit of 4.3%

In summary, Figure 4.2-2 illustrates the Wind's first pass comparability to the Dispatcable fleet's characteristic on both the XEFORd and EFORd basis. This indicates that the 2010 ELCC determined 8% is between the two values of 4.3% and 11.5% on the Wind characteristic curve. Other illustrations of the Wind and Dispatchable fleet's performance at peak times are shown in Appendix E.

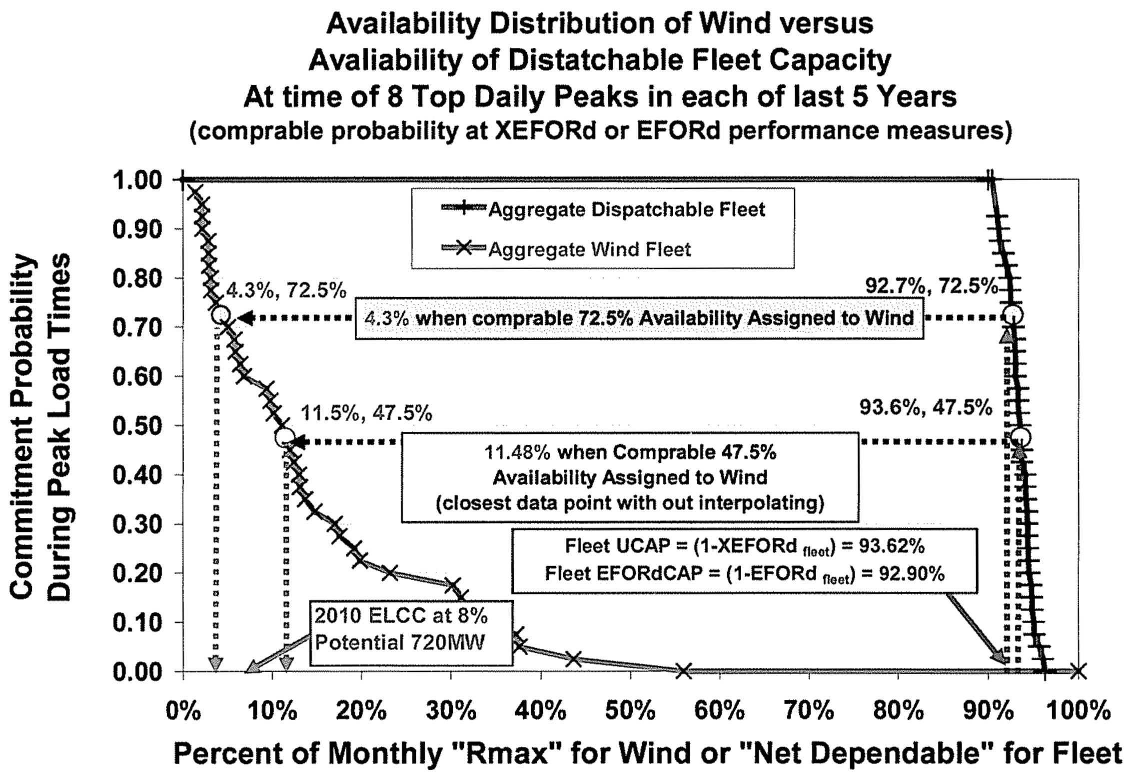


Figure 4.2-2 Benchmarking Wind and Dispatchable Fleet On a quasi XEFORd and EFORd Basis

4.2.2. Determination of Wind Capacity Credit for Module E

The calculation method uses a technique to determine the Equivalent Load Carrying Capacity (ELCC) of the wind generation to calculate a more precise value for wind capacity versus the comparison in Figure 4.2-1, or a historical median or average metric. This is required because the ELCC for Wind is dependent on the penetration level. The ELCC method is linked to using a LOLE application such as GE MARS used by the Midwest ISO. The ELCC metric is also commonly utilized by the National Renewable Energy Laboratory (NREL) when studying wind resources.

The process involves running an LOLE simulation with a historical hourly wind output pattern that is synchronized in time with the historical hourly load pattern. In a second run of the LOLE case, the wind is replaced with a fixed MW capacity adjustment, and the size of that adjust is varied until the annual LOLE result equals the LOLE level in the original wind pattern case. The resulting capacity adjustment MW divided by the Registered Max wind capacity represented in the original case is the Effective Load Carrying Capacity for the year simulated. The results for 5 years are illustrated in Figure 4.2-3. Tracking along a trend line of all 5 years' results, the value for the expected 9 GW Registered Max wind capacity for the summer of 2010 has an ELCC of about 8.0%., and as the capacity penetration would increases to 30 GW the ELCC decreases to about 5.7%. One would expect that the load would be somewhat higher by the time the 30 GW penetration would occur, and it is also possible that the characteristic of the base ELCC could change if the emerging future wind fleet evolved to having greater geographically diversity. Compared to some other systems, the current geographic diversity of the wind in the Midwest ISO Market is already fairly diverse. The Midwest ISO is party to other studies that are examining the benefits of even greater geographic diversity.

Prior to this study the Midwest ISO had allowed a capacity credit for wind resources brought to Module E of the Tariff equal to 20% of the Registered Max MW associated with each wind resource with firm transmission. As a result of this new study the allowed wind capacity credit is being set at 8.0% for the Planning Year 2010. Figure 4.2-3 suggests that the ELCC for wind is likely to decrease because the amount of wind capacity will likely become a factor. For example the 30 GW level represents capacity that is on the order of one third of the peak load. For example, if an annual median output level of about 5.7% were to occur, the effect upon LOLE analysis is as if there were a single 1,710 MW unit on the system (0.057 x 30,000 = 1,710 MW). Regardless of the driving resource (i.e. wind, coal, etc.), that size unit has greater impact than the current largest units or contingency events now in the 1,000 to 1,500 MW range. A discussion of wind modeling methods utilized and considerations for future analysis are included in Appendix E Wind Capacity Credit.

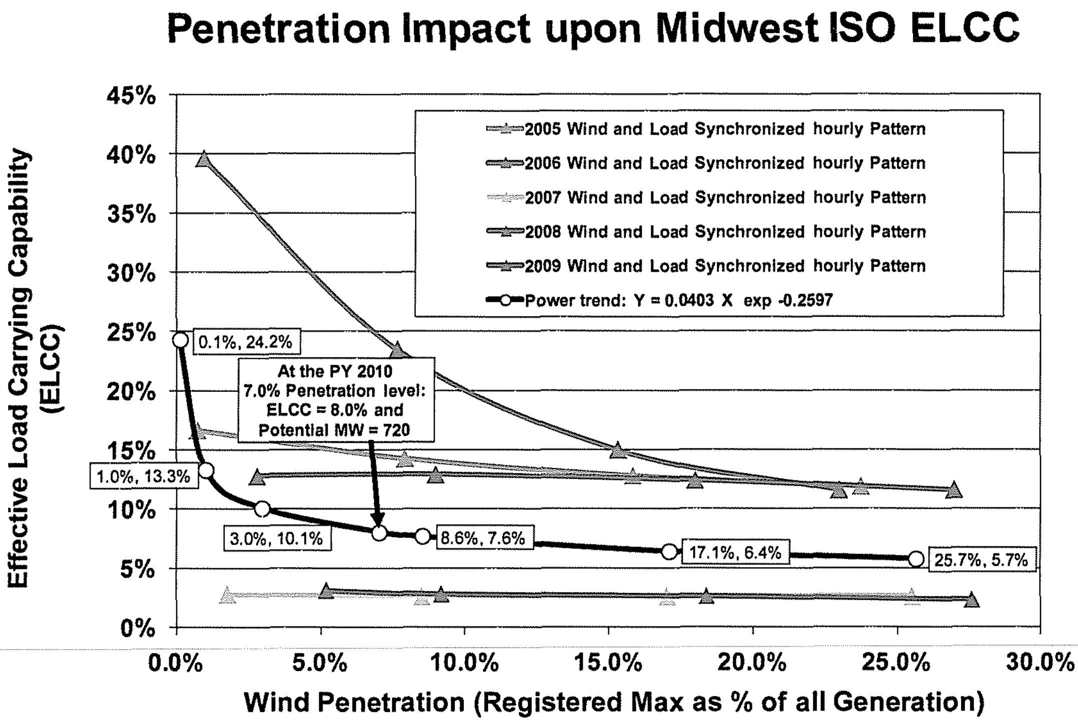


Figure 4.2-3 ELCC for Wind Versus Wind Capacity Penetration

4.3. Congestion Impact

Congestion incorporates the notion of aggregate deliverability impact between zones in GE-MARS, and a quantifiable MW capacity impact upon LOLE achieved by modeling the zones on a congestion-driven basis. Zones are developed from the process that utilizes two stages of PROMOD IV®. The steps are outlined in the Module E Tariff and the Resource Adequacy Business Practice Manual. This process also applies to the GE-MARS zones developed for Planning Years 2014 and 2019 in Section 5. One stage identifies the zones impacted by congestion and keys of the sign of the (MCC - $/MWh). A second stage of PROMOD IV® determines the amount of transmission support (EITC and/or EETC – MWs) that is available into or out of the zone. Figure 2.2 2010 GE MARS Modeled Zones is a geographical depiction of the resulting zones, that emerged from the raw output illustrated in Figure 4.4.1-1. Figure 4.2.2-1 is a view of the more direct information resulting from the first stage 2009 PROMOD IV® run. The blue zones indicate zones where generation resources tend to have their schedules reduced as a result of managing congestion, and the red zones are zones where generation schedules are increased in order to maintain reliable operations to serve load. The yellow areas are indifferent to congestion at time of summer peak conditions. Figure 2.2 2010 GE MARS Modeled Zones shows the quantitative metrics (load, generation, and tie values) that were developed from the PROMOD IV® zonal analysis, and is an illustration of the input to the GE MARS LOLE program.

2010 Jul 19 – Jul 25
Peak Hours MCC Sign

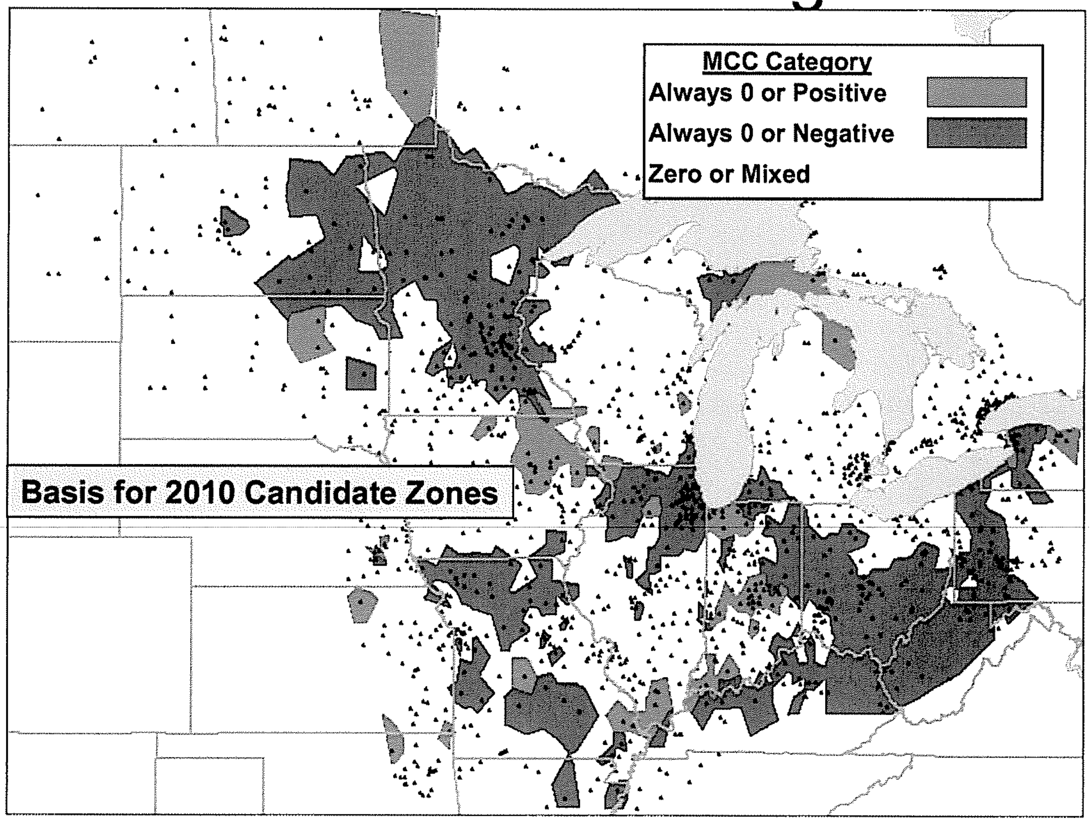


Figure 4.2.2-1 Illustration of clusters from first stage PROMOD IV® analysis results For Planning Year 2010

5. Years 2011 through 2019

5.1. GE MARS EFORd cases for 2014 and 2019

The GE MARS LOLE program was utilized again to determine planning reserve margins (PRM) for 2014 and 2019. The program utilization for these future years analysis was very similar to the assessment done previously for the 2010 planning year, but including the appropriate modeling changes in load forecast, unit additions or retirements and transmission modifications. The Load Forecast Uncertainty (LFU) was held constant for the analysis of the future years and the same value for the initial planning period was utilized. This ensures that year one and future planning years are comparable and acknowledge that when a future year is studied later as planning year one the uncertainty will decrease. In both the 2014 and 2019 cases, Equivalent Forced Outage Rate Demand (EFORd) from GADS data over the historical period 2005 through 2009 was utilized as the modeled unit forced outage rate.

Using the same process as was done for the year 2010; new internal zones were developed for years 2014 and 2019 with the specific tie limits for each year. These inputs were modeled and the planning reserve margin was calculated for a 2014 case and a 2019 case.

5.1.1. Utilize 2014 and 2019 External Equivalent zones

The same 2010 external equivalent zones configuration was utilized for the 2014 and 2019 analysis. External load growth and known unit additions and retirements where applied to the external system. The historically observed external Effective Import Tie Capacity (EITC) value of 6,320 MW was left unchanged from the 2010 model. As was done with the 2010 model, the 2014 and 2019 external systems were held to the same 0.1 day per year reliability level as the internal system, by adjusting the external load level as needed to sustain the external LOLE at 0.1.

5.1.2. 2014 Zone Analysis

Internal zones for 2014 were determined using the same process as was used to determine zones for 2010. The model and data used for this analysis was obtained from the Midwest ISO Top Congested Flowgate Study as a starting point. The base power flow model used was the MTEP 09 2014 Summer Peak model, which includes Appendix A and B projects. During the course of expansion planning hypothetical Regional Resource Forecast units area added and Transmission Overlays are developed to support these units. Regional Resource Forecast units and associated Transmission Overlays were excluded from the model utilized for the Zonal Analysis process. The first stage output of sign based MCC clusters form the PROMOD analysis is shown in Figure 5.1.2-1, and Figure 5.1.2-2 shows the final GE-MARS modeled zones. All candidate zones that were found to meet the 2,000 MW size thresholds were retained as modeled zones. Transfer limits were found for the 3 export zones and 1 import zone and the results input into the GE-MARS model. The quantitative values for each zones load, generation, and tie ratings for the 2018 GE-MARS model can be found in Figure 5.1.2-3.

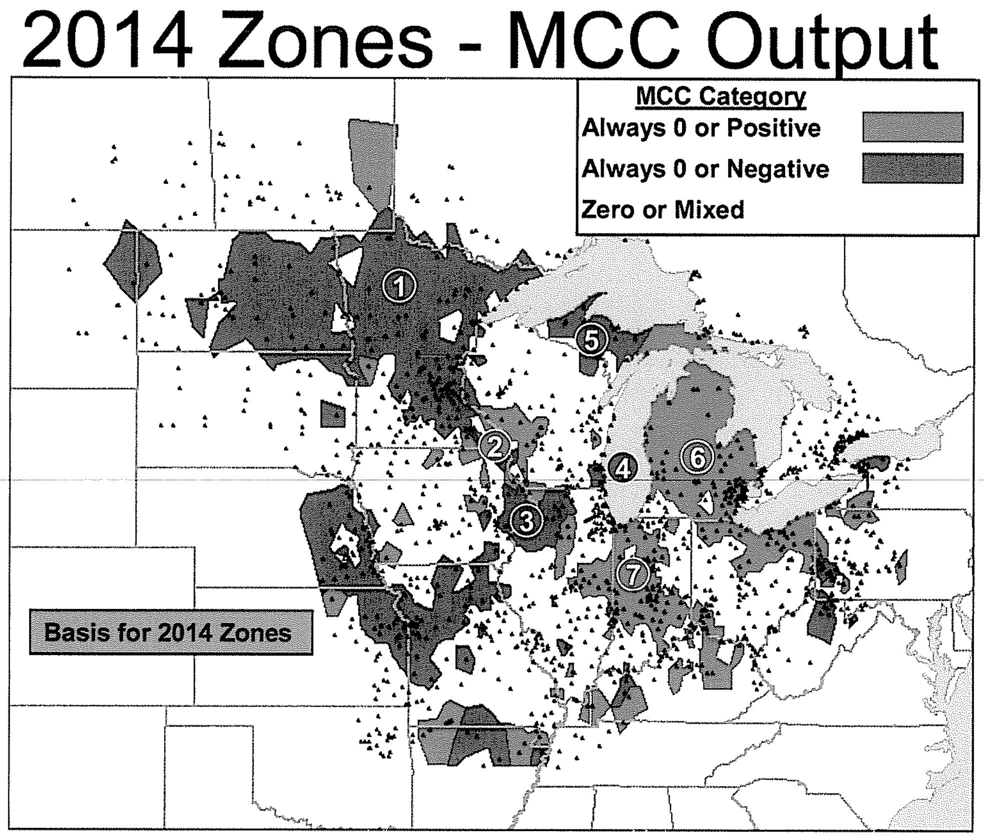


Figure 5.1.2-1 Illustration of clusters from first stage PROMOD IV® analysis results for Planning Year 2014

2014 Zones (after size check)

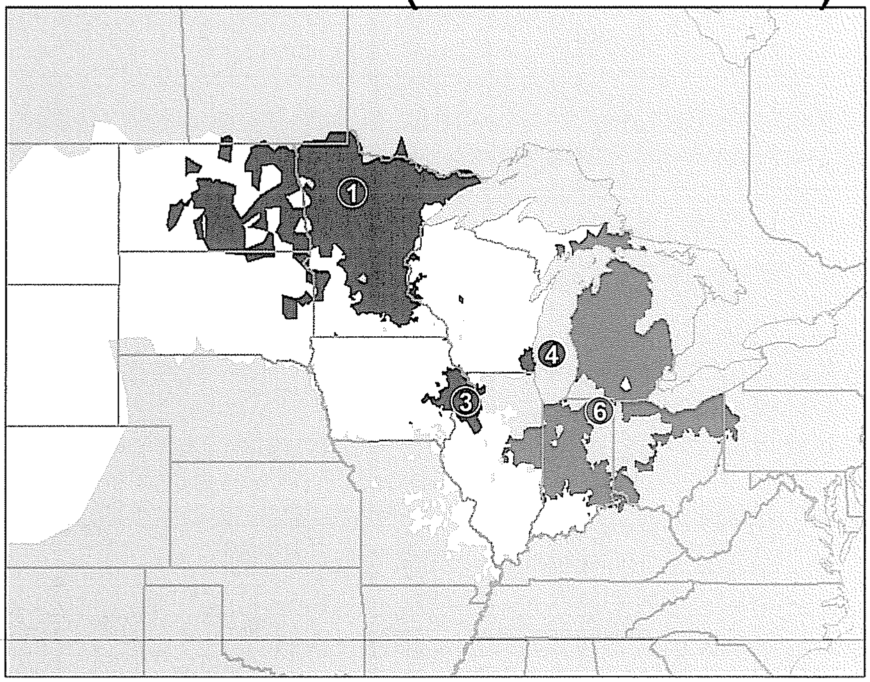


Figure 5.1.2-2 Congestion Based Zones Modeled in 2014

LOLE 2014 Model Input Values for the month of July (peak load month)

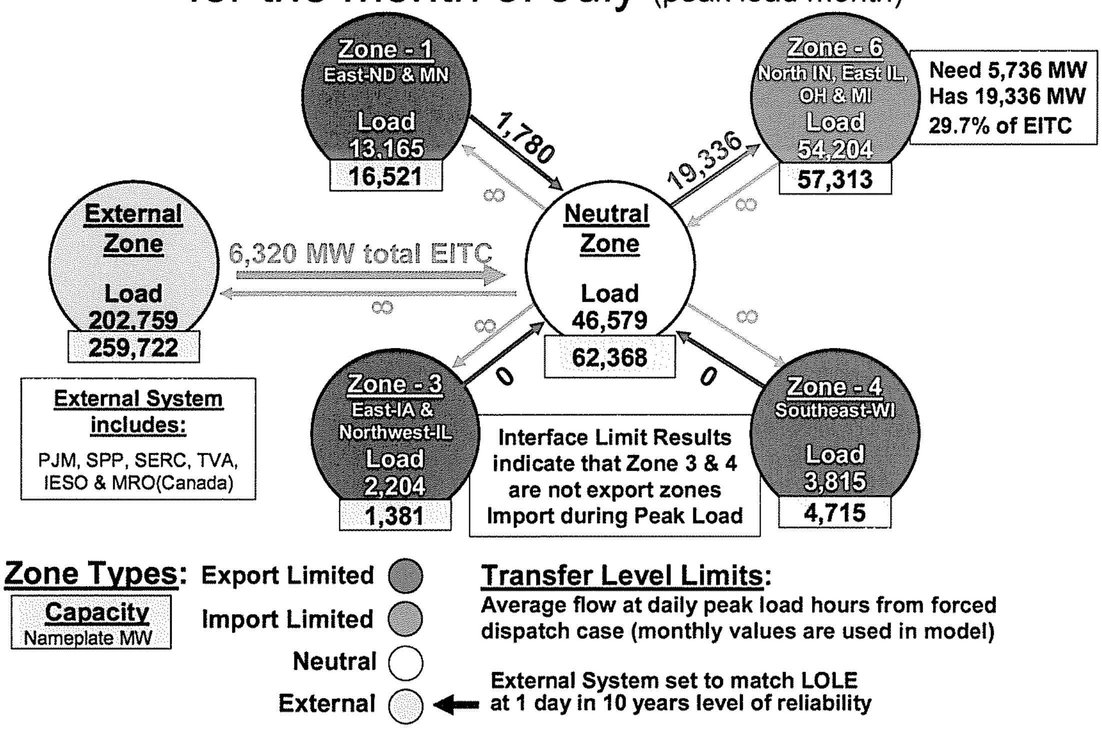


Figure 5.1.2-3 Zones and Parameters Modeled in 2014 GE MARS

5.1.3. 2019 Zone Analysis

Internal zones for 2019 were determined using the same process as was used to determine zones for 2010. The model and data used for this analysis was obtained from the Midwest ISO Top Congested Flowgate Study as a starting point. The base power flow model used was the MTEP 09 2019 Summer Peak model, which includes Appendix A and B projects. During the course of expansion planning hypothetical Regional Resource Forecast units area added and Transmission Overlays are developed to support these units. Regional Resource Forecast units and associated Transmission Overlays were excluded from the model utilized for the Zonal Analysis process. The first stage output of sign based MCC clusters form the PROMOD analysis is shown in Figure 5.1.3-1, and Figure 5.1.3-2 shows the final GE-MARS modeled zones. All candidate zones that were found to meet the 2,000 MW size thresholds were retained as modeled zones. Transfer limits were found for 1 export zone and 1 import zone and the results input into the GE-MARS model. The quantitative values for each zones load, generation, and tie ratings for the 2018 GE-MARS model can be found in Figure 5.1.3-3.

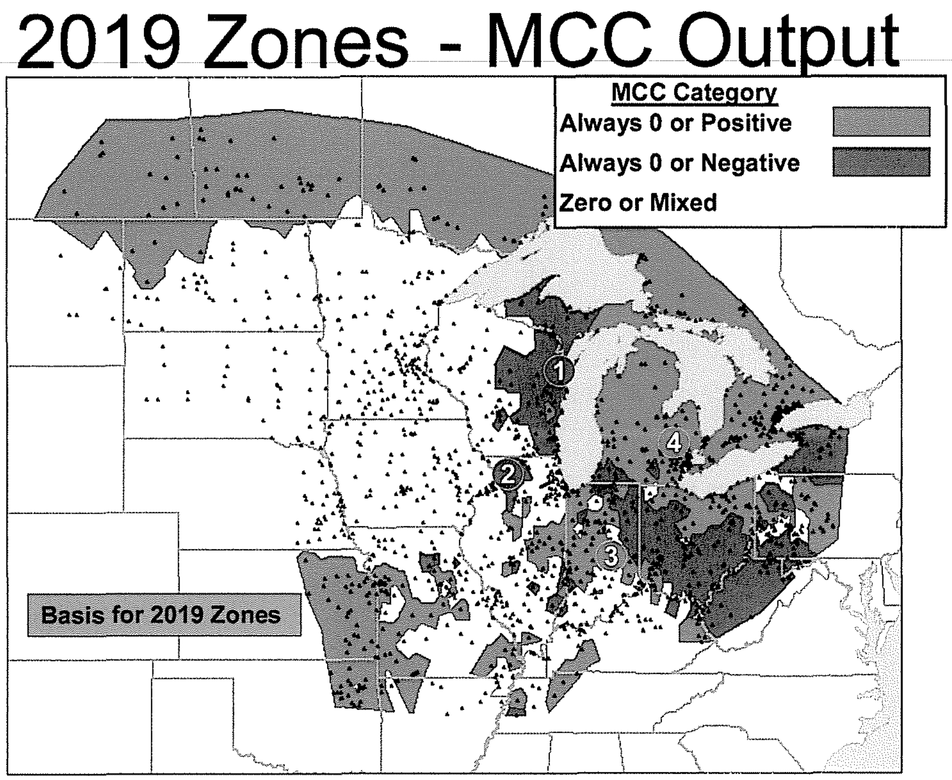


Figure 5.1.3-1 Illustration of clusters from first stage PROMOD IV® analysis results for Planning Year 2019

2019 Zones

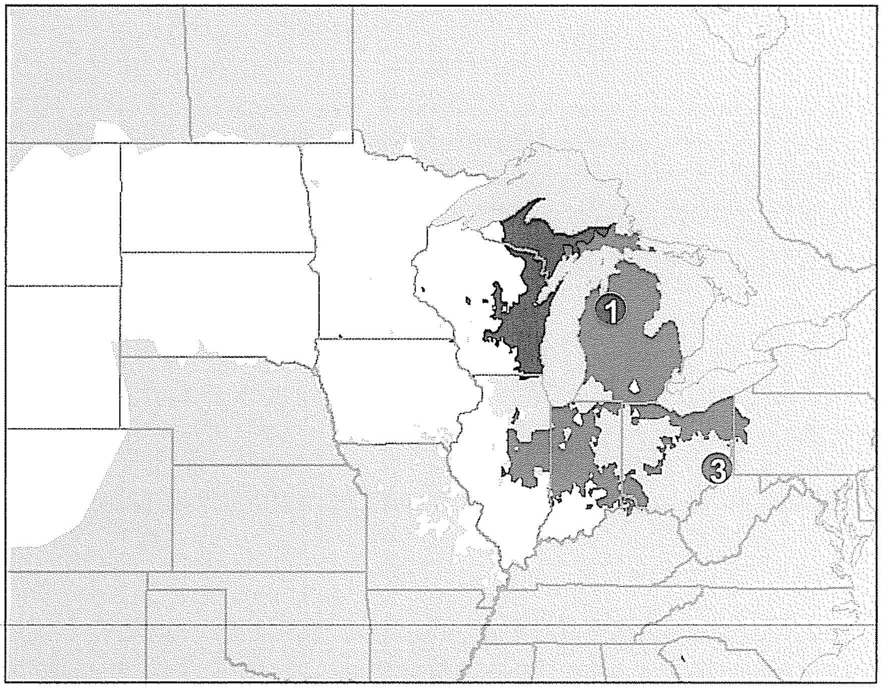


Figure 5.1.3-2 Congestion Based Zones Modeled in 2019

LOLE 2019 Model Input Values for the month of July (peak load month)

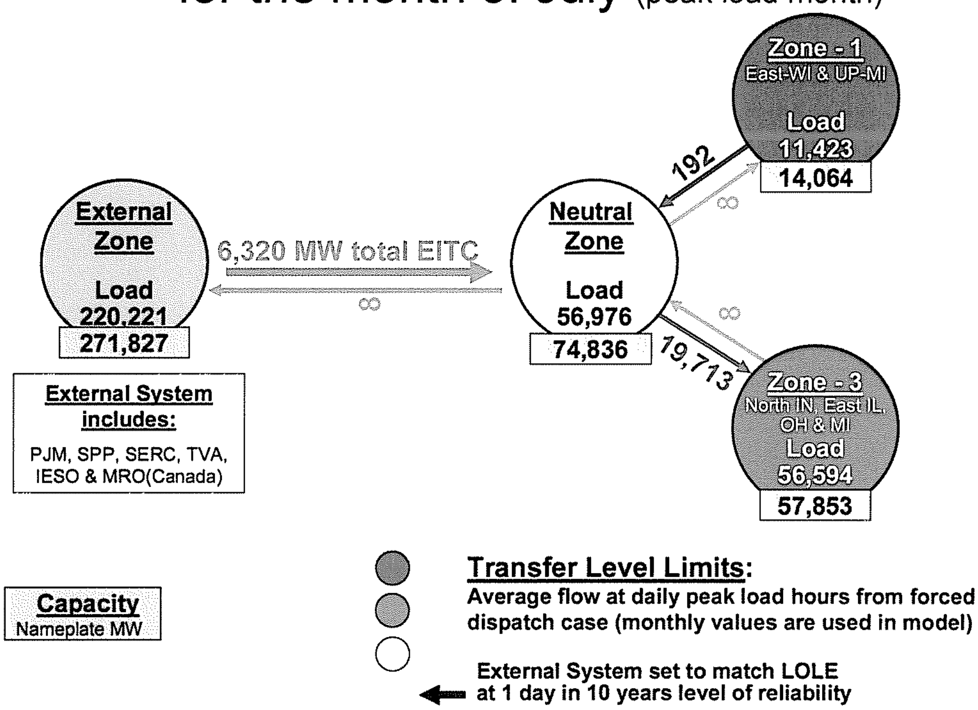


Figure 5.1.3-3 Zones and Parameters Modeled in 2019 GE MARS

5.2. Expected PRM for 2010-2019

For the two intervals of time for years 2011 through 2013, and 2015 through 2018, the planning reserve margins with no congestion, and congestion adder (top two rows in Table 7); were calculated by interpolating the results on a straight-line basis between the detailed cases that were done for years 2010, 2014 and 2019. In all years the third row was determined as the sum of rows 1 and 2. The expected $PRM_{SYSIGEN}$ from these interpolations can be seen for all years in Table 7, where everything that was explicitly calculated is in red font, and all interpolated values are shown as blue font.

Table 4: Expected $PRM_{SYSIGEN}$ for 2010-2019

	Year									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
$PRM_{SYSIGEN}$ (Results Ignoring Congestion)	15.0%	14.9%	14.9%	14.8%	14.7%	14.6%	14.4%	14.3%	14.1%	14.0%
$PRM_{SYSIGEN}$ (Congestion Contribution)	0.4%	0.8%	1.1%	1.5%	1.8%	1.6%	1.4%	1.3%	1.1%	0.9%
$PRM_{SYSIGEN}$ (Accounting for Congestion)	15.4%	15.7%	16.0%	16.2%	16.5%	16.2%	15.9%	15.5%	15.2%	14.9%

The analysis indicates the amount of PRM, ignoring congestion, decreases steadily over the 10 year period from 15% to 14%. This decrease can be explained by new units coming online with better class average forced outage rates. New units get assigned class average forced outage rates because there is no performance history to calculate unit specific rates. Also by comparing the results ignoring congestion, the effects of zone definition, location and size have been neutralized by essentially studying a "Copper-Sheet" or One Zone System.

The results show that the congestion contribution to the $PRM_{SYSIGEN}$ significantly increases for the first half of the 10 year period before decreasing in 2019 to 0.9%, which is half of the value it peaked at in 2014 (1.8%). The change in congestion can be attributed to the change in size of the export limited system. The export zones for 2014 cover both a larger geographical area and contain more capacity and load than the single export zone for 2019. The expectation that congestion will improve at a future date is consistent with future transmission expansion plans. As the 2019 results indicate, decreasing congestion can help lower the overall planning reserve margin.

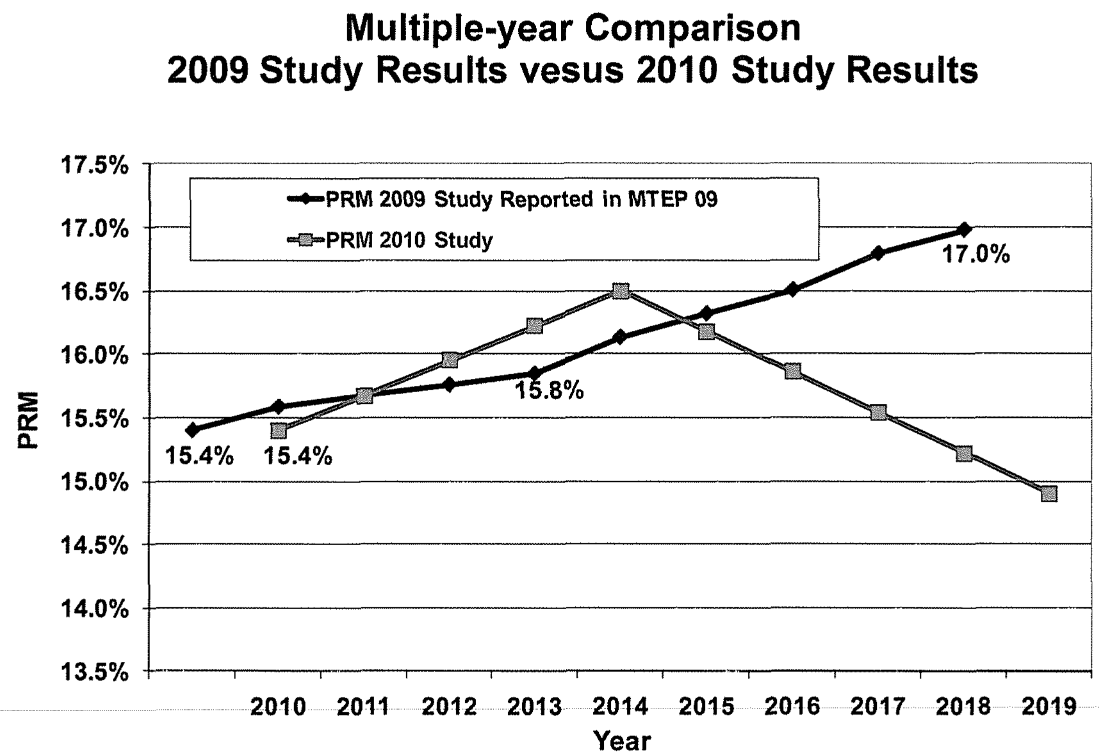


Figure 5.2 – Multiple-year PRM Comparison

Table 6: Load and Capability for 2010-2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reserve Margin (MW)	35,178	33,743	34,302	34,522	33,965	33,282	32,350	32,078	31,854	30,916
Reserve Margin (%)	34.7%	32.4%	32.8%	32.9%	32.1%	31.2%	30.1%	29.6%	29.1%	28.0%
Reserve Requirement (%)	15.4%	15.7%	16.0%	16.2%	16.5%	16.2%	15.9%	15.5%	15.2%	14.9%

Reserve Margins from 2009 Long Term Reliability Assessment Nameplate Capacity and Queue Additions.

Appendix A Load Forecast Uncertainty (LFU) Final Report

Previous Year Report

This report outlines the study work that the Load Forecast Uncertainty Task Team undertook for the 2009 LOLE study. Due to the timing of the NERC bandwidths release, the 2010 task team recommended the use of the same findings for this year's study.

Scope

Apply MISO stakeholder expertise in load forecasting together with the resident MISO expertise to determine the annual uncertainty associated with the variance between actual load and the 50/50 forecast load. The LFU is for the 2009 planning period and for the subsequent nine planning years. The work product of the LOLEWG-LFU Task Team will be recommended and presented to the LOLEWG by October 10, 2008. Load Forecast Uncertainty is the result of weather, economic, and demographic factors. It is not forecast error or one's ability to forecast accurately given the limitations of the models available for use.

Executive Summary

The Load Forecast Uncertainty Task Team recommends the use of the Summation of the NERC Variances method to calculate the load forecast uncertainty value necessary for GE MARS. This method produces a sigma value of 4.04% in the summer and a sigma value of 4.08% in the winter. The benefits of using the Summation of the NERC Variances are that the method has a solid methodology and most of the work has been completed through the NERC Load Forecasting Working Group (LFWG). The Load Forecast Uncertainty Task Team also recommends the use of a constant 4.04% summer LFU and 4.08% LFU value for years 2-10 analysis with one sensitivity case with a 5 year out LFU value of 8.95% in the summer and 7.14% in the winter.

Overview

The Load Forecast Uncertainty (LFU) Task Team was created to help develop a recommendation of the methods in which to obtain a value for Load Forecast Uncertainty to the Loss of Load Expectation Working Group (LOLEWG). Initial work had been started by Ryan Westphal of Midwest ISO previous to the forming of the LFU Task Team. His work was the starting point for this group. This group was comprised of subject matter experts from the MISO stakeholder community. This group typically meets on a monthly basis, half day before the full day LOLE WG meeting.

1. Monthly Peak Comparison

The monthly peak comparison work was the starting point in trying to determine a value for LFU. The summer and winter assessments use the same method for their determination of the 90/10 and 10/90 bands. The Load Forecast Uncertainty (LFU) value is derived from variance analysis to determine how likely monthly peak forecasts will deviate from actual monthly peak load. In order to establish a Load Forecast Uncertainty value three years of real-time load data was compared to forecasts for those same periods. Load forecasts for the months of June, July and August for summer and December, January, and February for winter were adjusted for the reported demand side management programs to arrive at coincident Net Internal Demand forecast values. Those monthly forecasts were compared to the actual monthly peak loads of the same period and the differences compiled into a sample space from which to derive a standard deviation. A load forecast uncertainty of approximately 4.1% for the summer was calculated using this methodology. A graph of the monthly peaks is available in the appendix (Graph 1.1). For this model a normal distribution is assumed. From the graph we can see that the sample space for data is three years.

2. Weather Sorting Model

A weather sorting model was developed to evaluate LFU. The weather sorting model gives us a long statistical history. Since this model derives its statistical analysis from weather a long history of load is not needed. A long history of weather variables is easily obtained. The weather variables, specifically heat index, are then used to determine the sigma of the heat index over a 25 year history (Graph 2.1). To capture how load is affected by weather at the entire MISO footprint level a composite temperature is developed. The composite heat index is a load weighted average of the heat index at each weather station that is selected to represent the heat index for that balancing authority. To see how load responded to the composite heat index at each daily peak, the load and composite heat index are plotted together. The result of this plot is available in the appendix (Graph 2.2). From this graph we can use the equation to determine the number of MW's that are affected for each degree of heat index. If we assume that the equation representing weather above 72 degrees F is linear we get an equation of:

$$Y(x) = 1742 * x - 62332 \tag{1}$$

Where Y equals MW's and x equals degrees F. If we take the derivative of equation (1) we get the following equation.

$$\frac{dy}{dx} = 1742 \tag{2}$$

Equation 2 states that for every unit change in x there is a 1742 unit change in y or for every change in degree F there is a 1742 MW change in load. From the model we can now construct the following table (2.1).

Table 2.1: Results to calculate LFU

(1)	(2)	(3)	(4)	(5)
Heat Index(F)	Standard Deviations	Delta Heat Index	MW/deg	MW
80.9	-3	-8.1	1742	-14110.2
83.6	-2	-5.4	1742	-9406.8
86.3	-1	-2.7	1742	-4703.4
89.0	0	0.0	1742	0.0
91.7	+1	2.7	1742	4703.4
94.4	+2	5.4	1742	9406.8
97.1	+3	8.1	1742	14110.2

Column number 5 is calculated by multiplying columns 3 and 4 together. Using this method a sigma of 4.4% is calculated.

3. Other Studies

A presentation was given showing the different values and method other regions are using for their studies. Looking at other regions we can evaluate a reasonable number to apply in the Midwest ISO LOLEWG study. From the presentation a "Band of Reasonability" of 4-5% sigma was created. A link to the presentation is provided below.

http://www.midwestiso.org/publish/Document/81d7e_11b6e66e758_-7a4b0a48324a?rev=1

4. Summation of the NERC Variances

NERC develops its own uncertainty bands for each of the NERC regions. This method will use these uncertainty bands with a load weighted variance calculation to determine the MISO-wide sigma. Three NERC regions have portions of their load in MISO. Those three regions are MRO US, SERC and RFC. To calculate the weights each MISO load balancing authority is assigned to its appropriate NERC regions and then the percent of the MISO load within the region is the weight used for the calculation. The NERC bands are stated in 90/10 and 10/90 projections. To convert those to a sigma value we divide by 1.28. This corresponds to the x-value from the unit normal distribution for the 90/10 and 10/90 bands. The general equation for summing random variables variances is used to determine the weighted variance for MISO.

$$(1)\ \ var(a_x x + a_y y) = a_x^2 * var(x) + a_y^2 * var(y) + 2 * cor(x,y) * a_x * std(x) * a_y * std(y)$$

$$(2)\ \ var(x) = std(x)^2$$

Plugging (2) into (1)

$$(3)\ \ std(a_x x + a_y y)^2 = a_x^2 * std(x)^2 + a_y^2 * std(y)^2 + 2 * cor(x,y) * a_x * std(x) * a_y * std(y)$$

Expanded to three variables

$$std(a_x x + a_y y + a_z z)^2 = a_x^2 * std(x)^2 + a_y^2 * std(y)^2 + a_z^2 * std(z)^2 + 2 * cor(x,y) * a_x * std(x) * a_y * std(y) + 2 * cor(x,z) * a_x * std(x) * a_z * std(z) + 2 * cor(y,z) * a_y * std(y) * a_z * std(z)$$

If $cor(x,y) = 1$

$$std(x+y) = \sqrt{a_x^2 * std(x)^2 + a_x^2 * std(y)^2 + 2 * a_x * std(x) * a_y * std(y)}$$

$$std(x+y) = \sqrt{[a_x * std(x) + a_y * std(y)]^2}$$

$$std(x+y) = a_x * std(x) + a_y * std(y)$$

If $cor(x,y) = 0$

$$std(x+y) = \sqrt{a_x^2 * std(x)^2 + a_y^2 * std(y)^2}$$

As we can see from the above equation we have to make an assumption about the correlation between the three regions. It was suggested within the LFU Task Team to use the MISO coincident factor of .96 in the summer and .97 in the winter as the correlation between the three regions. Table 4.1 and 4.2 within the appendix summarizes the results of the Summation of the NERC Variances. The Summation of the NERC Variances produces a sigma of 4.04% in the summer and 4.08% in the winter.

5. 2-10 Year Analysis

The LFU Task Team ran the Summation of NERC Variance results through the MARS software to help determine how to model LFU in the 2-10 year LOLE analysis. Three summer LFU numbers were run in the MARS software, first year LFU of 4.04%, 5 year LFU of 8.95% and 10 year LFU of 12.50%. Graph 5.1 in the appendix summarizes all values calculated from the Summation of NERC Variances. The results of the analysis are shown in the following table 5.1.

Table 5.1 MARS results with increasing LFU

	% Reserve Margin	Total System MW	Total System Demand	Incremental MW needed to meet 1 day in 10
Year 1	13.88%	115,786	101,671	0
Year 5	17.38%	129,551	110,372	13,765
Year 10	30.04%	151,051	116,160	35,265

From the table we see that in year 10 a 30.04% reserve margin is needed to meet the 1 day in 10 criteria. The LFU Task Team believes this is unreasonable and if the LFU is grown it must be capped from growing at some point. The LFU Task Team believes that capping the LFU at the 5 year number would be representative of the time it takes to get capacity built and recommends that the LFU be capped at the 5 year value.

The LFU Task Team further discussed that holding the LFU constant at the 1 year value for all years would better represent what reserve margins that can be expected to be seen in each year. It was thought that once we get the each subsequent year that an LFU value would be closer to the 1 year out value, meaning that, once you get to year 5 the LFU value will be a 1 year out LFU value.

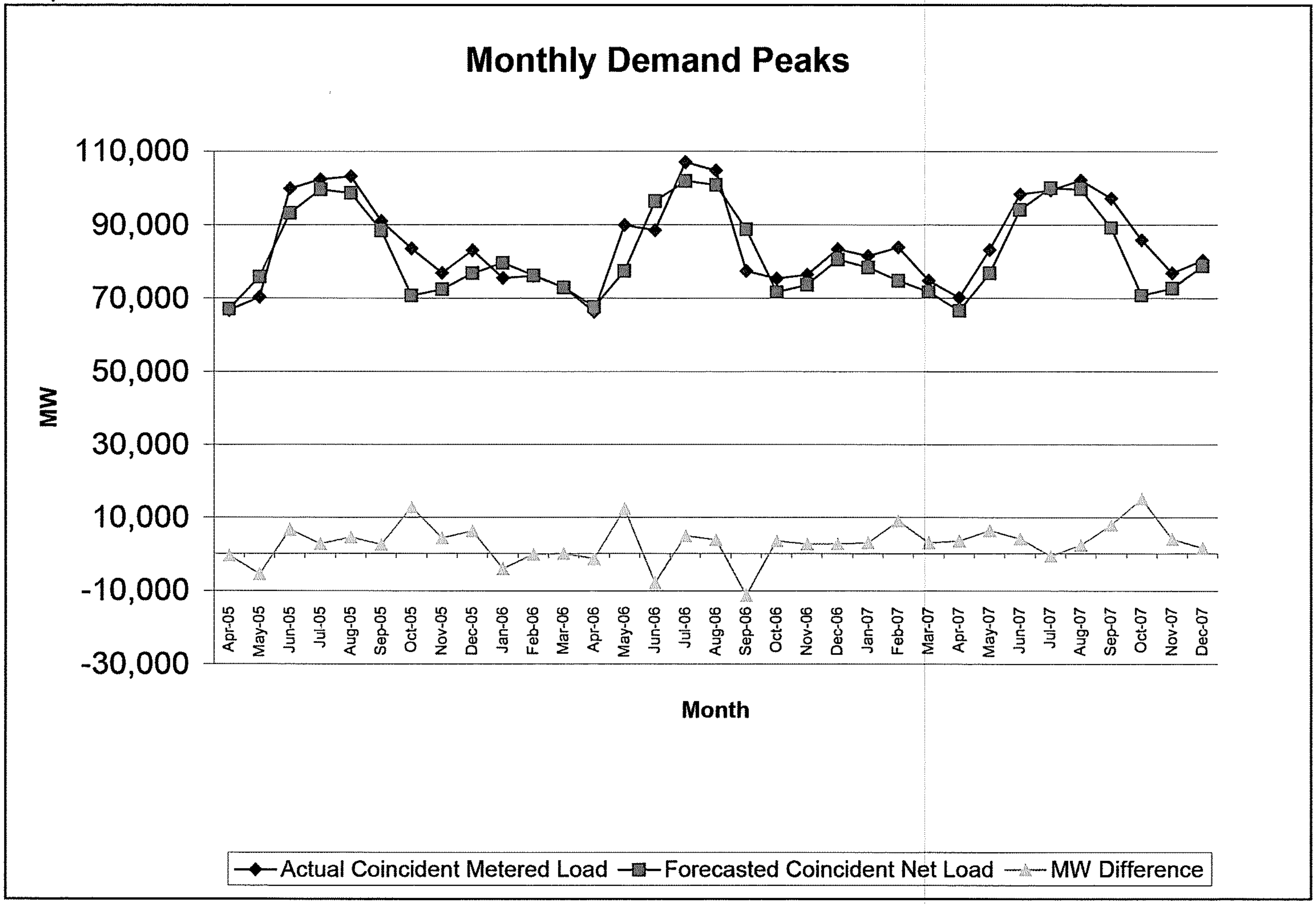
6. LFU Task Team Recommendation

The LFU Task Team is recommending the use of the Summation of the NERC Variances to the LOLE WG. This method has the benefits of being tried and tested before and much of the work is complete through the NERC LFWG. Also looking at the other studies performed in the LFU Task Team each study results seem to converge to a similar number. The sigma values that are calculated through the Summation of the NERC Variances are a sigma of 4.04% in the summer and 4.08% in the winter. In the future of the LFU Task Team the Weather Sorting model will be helpful in sanity checking and possible using it in a future study where weather correcting is necessary.

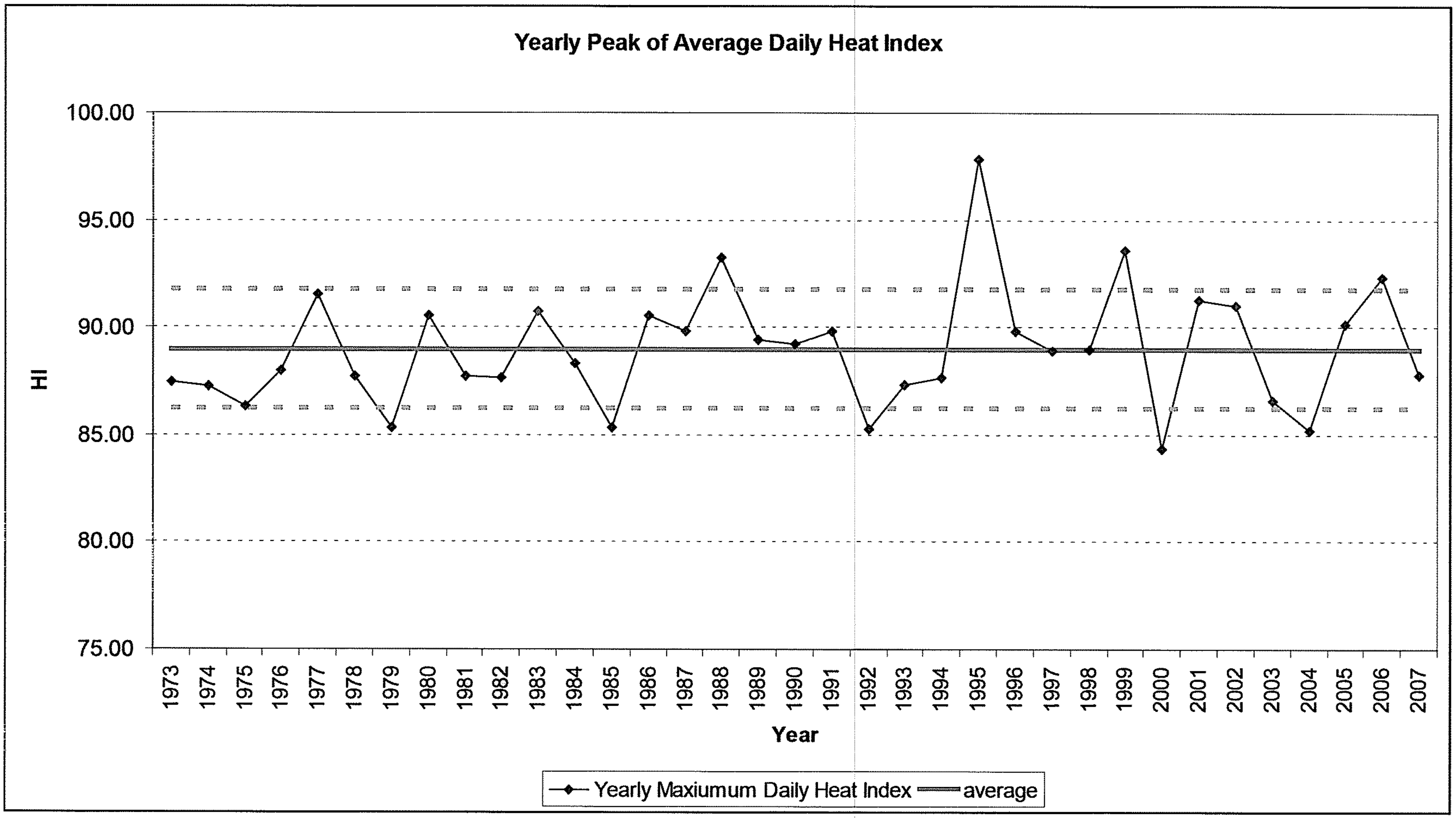
The LFU Task Team recommends running years 2-10 with a fixed 1 year out LFU of 4.04% in the summer and 4.08% in the winter. The LFU Task Team also recommends running one case with a 5 year out value or 8.95% in the summer and 7.14% in the winter.

LFU Appendix

Graph 1.1

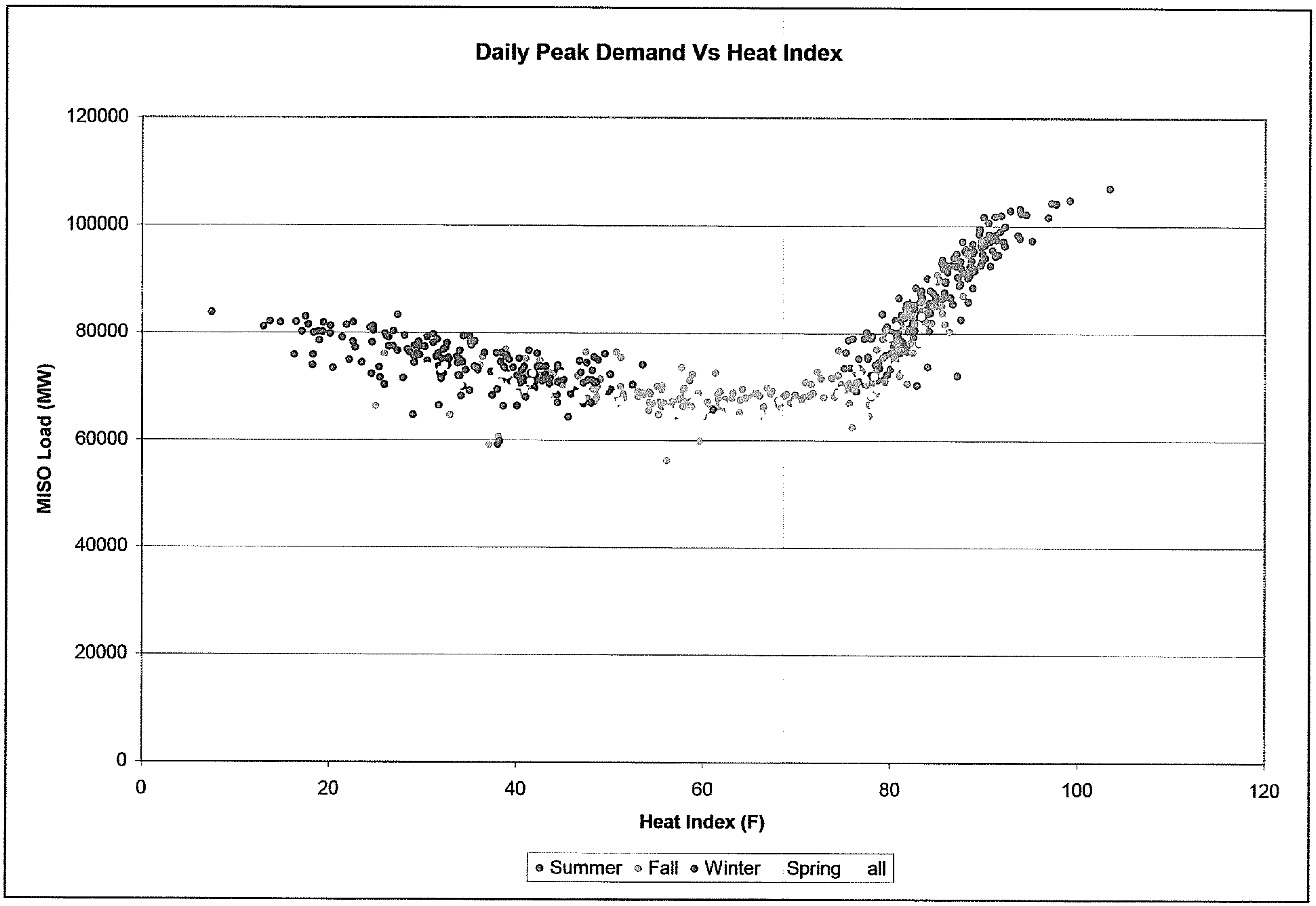


Graph 2.1



Yearly Peak of Average Daily Heat Index
100.00
95.00
90.00
85.00
80.00
75.00
HI
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
Year
Yearly Maxiumum Daily Heat Index
average

Graph 2.2



Daily Peak Demand Vs Heat Index
120000
100000
80000
60000
40000
20000
0
MISO Load (MW)
0
20
40
60
80
100
120
Heat Index (F)
Summer
Fall
Winter
Spring
all

Table 4.1

Summer

Year		WEIGHTING FACTOR	(WEIGHTING FACTOR)^2	NERC 10% band	Z α/2	σ	σ^2 or Variance	(WEIGHTING FACTOR)^2 * σ^2	(WEIGHTING FACTOR) * σ
1	RFC	0.586665	0.344176	5.69%	1.2816	4.44%	0.197%	0.000678215	0.026042563
1	SERC	0.167625	0.028098	4.66%	1.2816	3.63%	0.132%	3.71079E-05	0.006091625
1	MRO-US	0.245710	0.060373	4.56%	1.2816	3.56%	0.126%	7.63543E-05	0.008738095

Perfectly Correlated	4.09%
Perfectly independent	2.81%

------------->

0.96 Correlation

4.04%

Correlation	0.96

Table 4.2

Winter

Year		WEIGHTING FACTOR	(WEIGHTING FACTOR)^2	NERC 10% band	Z α/2	σ	σ^2 or Variance	(WEIGHTING FACTOR)^2 * σ^2	(WEIGHTING FACTOR) * σ
1	RFC	0.586665	0.344176	6.26%	1.2816	4.89%	0.239%	0.000821963	0.028669904
1	SERC	0.167625	0.028098	4.61%	1.2816	3.60%	0.129%	3.63582E-05	0.006029778
1	MRO-US	0.245710	0.060373	3.32%	1.2816	2.59%	0.067%	4.05526E-05	0.006368092

Perfectly Correlated	4.11%
Perfectly independent	3.00%

------------->

0.97 Correlation

4.08%

Correlation	0.97

Graph 5.1

Appendix B EFORd, XEFORd, UCAP Metrics, and OMC Codes

Appendix Item B.1
EFORd, IGEN and UCAP Relationships and Findings for 2010

1) For each generator:

IGEN (1- XEFORd $_{IGEN}$) = UCAP

Where: Installed Capacity = IGEN
Unforced Capacity = UCAP

2) For the total system results applied to an LSE with a 1,000 MW Non-coincident load:

PRM $_{IGENEFORd}$ = 11.94%, (3.00% diversity result highlighted value in Tables below)

System Average XEFORd = 6.644%, (6.83% from GADS data blended with assumed 0% XEFORd for Demand Resources = 6.644)

Forecast LSE Requirement = (Load + Load Modifying Resources) = 1,000 MW

IGEN Requirement= Forecast LSE Requirement * (1+PRM $_{IGENEFORd)}$ = 1,000 * (1+0.1194) = 1,119 MW

UCAP Requirement = ICAP Requirement * (1 – System Average XEFORd), and substituting values gives:

UCAP Requirement = 1,119 * (1 – 0.06644) = 1,045 MW

3) By applying the following equation to define PRM_{UCAP} metric:

(1 – System Average XEFORd) (1+$PRM_{IGENXEFORd}$) = (1+$PRM_{UCAPXEFORd}$)

$PRM_{IGENXEFORd}$= 11.94%, (3.00% diversity result highlighted value in Tables below)

System Average XEFORd = 6.644%
Then (1 – System Average XEFORd) = 0.9336

And,

$0.9336\ (1+0.1139) = 1 + PRM_{UCAP}$
$PRM_{UCAPXEFORd} = 0.9336\ (1+0.1139) - 1$
$\mathbf{PRM_{UCAPXEFORd} = 0.0399 = 3.99\%}$

The total PRM is represented by the **XEFORd** driven component $\mathbf{PRM_{UCAPXEFORd}}$ **= 3.99%** plus the system wide average **Force Majeure** component adder for generators of **0.52%**. Therefore, the total

$$\mathbf{PRM_{UCAPEFORd} = 3.99\ \% + 0.52\% = 4.50\%}$$

0.52% is the 3.00% diversity result **highlighted in Tables below**

4) Amount of Capacity Required for the Modeled Market Load

Coincident Load x 115.40% = 110,779 x 1.1540 = 127,839 MW_{IGEN}

And within round off error:

Non-coincident Load x 111.94% = 114,205 x 1.1194 = 127,839 MW_{IGEN}

Table B1 - Summary of IGEN versus UCAP
At 3.00% diversity for total Model footprint:

	Non-coincident Load Based		Coincident Load Based
Basis of PRM:	PRM_{UCAP} (%)	$PRM_{:LSEIGEN}$ (%)	$PRM_{SYSIGEN}$ (%)
With congestion XEFORd Generation and BTM	3.98%	11.39%	14.83%
System average Generator Force Majeure adder	0.52	0.55%	0.57%
With congestion EFORd Generation and BTM	4.50%	11.94%	15.40%
Load	114,205	114,205	110,779
Required Capacity	119,344 UCAP	127,839 IGEN	127,839 IGEN

Appendix Item B.2
OMC Codes used in Midwest ISO

The term $XEFOR_d$ represents calculating the forced outage rate by excluding OMC outage causes when performing the calculation that would otherwise compute the $EFOR_d$. Currently, the Midwest ISO study utilizes 27 cause codes in its OMC set of outages and otherwise uses the NERC default set of 36 OMC cause codes . The 27 OMC Codes approved by stakeholders for use in the Midwest ISO LOLE study as listed in the BPM are shown in Table C2 below.

Table B2 - Outage Cause Codes included in the OMC set for Midwest ISO Studies

Code	Description	Midwest ISO and PJM OMC List
3600	Switchyard transformers and associated cooling systems - external	1
3611	Switchyard circuit breakers - external	1
3612	Switchyard system protection devices - external	1
3619	Other switchyard equipment - external	1
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)	1
3720	Transmission equipment at the 1st substation) (see code 9300 if applicable)	1
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)	1
9000	Flood	1
9010	Fire, not related to a specific component	1
9020	Lightning	1
9025	Geomagnetic disturbance	1
9030	Earthquake	1
9035	Hurricane	1
9036	Storms (ice, snow, etc)	1
9040	Other catastrophe	1
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels	1
9135	Lack of water (hydro)	1
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.	1
9250	Low Btu coal	1

9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)	1
9320	Other miscellaneous external problems	1
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated	1
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated	1
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated	1
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated	1
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)	1
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)	1
	Total	**27**

The accommodation of Force Majeure outage causes by using the EFORd metric as the input data to the GE MARS application is normal; however a sensitivity run with the $XEFOR_d$ metric can be done to examine the impact of the Force Majeure.

Appendix C RE Compliance Conformance Tables

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	**Requirements under: Standard BAL-502-RFC-02**	**Response**
R1 The Planning Coordinator shall perform and possess the documentation of a planned Resource Adequacy assessment. **R1.1** Be performed annually unless a document summarizing a review of system data that concludes that changes to system data used in the assessment do not warrant such a study is provided to the MRO. A study is warranted if changes have occurred that require revisions in any key assumptions such as generation mix and transmission limitations that are not covered by a sensitivity study. The planned Resource Adequacy assessment is to be conducted for Year One through Year Ten. Year One is defined as the year that begins with the upcoming annual peak season.	**R1** The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The attached assessment is the annual Resource Adequacy Analysis.

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	**Requirements under: Standard BAL-502-RFC-02**	**Response**
R1.2 Be performed to meet a LOLP of no greater than 0.1 day in one (1) year which equals the sum of the LOLE for the integrated daily peak hours for each year. This shall be done for a minimum of 3 periods within the Year One through Year Ten (as defined in R1.1) to ensure meeting one (1) day in ten (10) years. These periods are Year One, a minimum of one year in years 2 through 5, and a minimum of one year in years 6 through 10. **R1.2.3** ~~Be performed for every day of each year throughout the period in R1.1~~. ←Conflicts with 3-year choice in R1.2 Expected Unserved Energy may be performed as the method to meet R1.2 provided the results of such an assessment is compared with an LOLP analysis and the comparison is documented.	**R1.1** Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.2 of this report outlines the utilization of LOLE in reserve margin determination. "Capacity adjustments were then put in place to alter the available capacity in each zone to ensure that the probabilities for loss of load within the Midwest ISO system over each integrated peak hour for the planning period summed to 1 day in 10 years or 0.1 days/year."
	R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.2 of this report: "Direct Control Load management and Interruptible Demand are included within the MARS model as load modifiers that can be utilized without incurring a loss of load event."

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	Requirements under: Standard BAL-502-RFC-02	Response
R1.4 Express the planning reserve as a percentage of the 50:50 probability forecast peak load (planning reserve margin).	**R1.1.2** The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).	Section 3.2 of this report: "When capacity was appropriately adjusted in each LOLE zone to bring all systems to a 0.1 days/year LOLE value the ratio of capacity to coincident load in the Midwest ISO yielded a reserve margin of 15.4% of the 50/50 net internal demand forecast."
	R1.2 Be performed or verified separately for each of the following planning years:	
	R1.2.1 Perform an analysis for Year One. .	In Section 4, a full analysis was performed for year 2010.
	R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	In Section 5, a full analysis was performed for the year 2014, Also outlined in Section 5 is an analysis for year 2019.
	R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year	Analysis was performed.
R1.3 Include, at a minimum, documentation of how and why the following were/were not included in the analysis:	**R1.3** Include the following subject matter and documentation of its use:	
R1.2.1 Use loads developed from the expected 50:50 probability load forecast, **R1.2.2** Include load forecast uncertainty such as uncertainty due to	**R1.3.1** Load forecast characteristics: • Median (50:50) forecast peak Load. • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic	• Section 2.1.7: "Load in PROMOD IV® is equivalent to the actual load plus losses as included in the 50/50 LSE forecasts." • LFU (Load Forecast Uncertainty) use within this assessment is outlined in Section 3.1.3 and Appendix A • Section 3.1 states that an hourly load profile was utilized: "The

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	Requirements under: Standard BAL-502-RFC-02	Response
load diversity, seasonal load variation, load variability due to other region economic forecasts or other factors. **R1.3.2** Load Characteristics **1.3.2.1** Load forecasts **1.3.2.2** Load forecast uncertainty **1.3.2.3** Load diversity **1.3.2.4** Seasonal load variations **1.3.2.5** Load variability due to weather, regional economic forecasts, etc. **1.3.2.6** Daily demand modeling assumptions (firm, interruptible)	forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	PROMOD IV® tool was used to group the buses as specified in Section 0 and output a single hourly load profile for each zone which included all hours within the period under scrutiny." • Section 3.2 of this report: "Direct Control Load management and Interruptible Demand are included within the MARS model as load modifiers that can be utilized without incurring a loss of load event." • Load diversity is discussed in Section 3.2: "…a diversity factor of 3.00% is used for the 2010/11 Planning Year. This value was applied to the coincident load used in the original reserve margin calculation to yield a non-coincident peak load from the system coincident peak. This increased load value was utilized to yield an 11.94% planning reserve margin as applied to individual LSE peaks." • Section 3.1: "Direct Control Load management and Interruptible Demand are included within the MARS model as load modifiers that can be utilized without incurring a loss of load event. In order to be included in the MARS model all Load Modifying Resources must first meet registration requirements through Module E. These requirements include, at a minimum: a shutdown time less than 12 hours, a maximum number of interruptions during the summer season greater than 5 and the ability to maintain interruption for 4 hours."

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	**Requirements under: Standard BAL-502-RFC-02**	**Response**
R1.3.1 Resource availabilities **1.3.1.1** Historic resource performance and any projected changes **1.3.1.2** Seasonal resource ratings **1.3.1.3** Modeling assumptions of non-conventional resources such as wind and cogeneration **1.3.1.4** Energy limitations of hydroelectric units. **1.3.1.5** Merchant plant availabilities **1.3.1.6** Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area **1.3.1.10** Available Demand-Side Management	**R1.3.2** Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis	• Section 3.1.2 outlines the inclusion of historical unit performance, seasonal maximum outputs, planned outage schedules or deratings, retirements, planned additions and energy limitations in the LOLE model. • Section 3.1.1 outlines the handling of capacity purchases and sales within the assessment. • Section 3.1.4 states that wind resources are not included in the resource assessment and the reasoning for their exclusion.

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	Requirements under: Standard BAL-502-RFC-02	Response
R1.3.3 Transmission limitations that prevent the delivery of generation reserves **1.3.3.1** Transmission maintenance outage schedules. **1.3.3.2** Transmission forced outage rates **1.3.3.3** Transmission availability for emergency considering firm commitments	**R1.3.3** Transmission limitations that prevent the delivery of generation reserves	As outlined in Section 3.1: "Each generator within a zone is assumed to be deliverable to all load within that zone."
	R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Section 5 states that transmission facilities included in Appendix A and B are included in the analysis.
R1.3.5 Emergency assistance from other interconnected systems including multi-area assessment considering transmission limitations	**R1.3.4** Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.1.1 shows the derivation of external assistance limitations.

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	Requirements under: Standard BAL-502-RFC-02	Response
R1.3.4 Modeling assumptions for emergency operation procedures used during unexpected resource outages. **R1.3.6** Document and justify the inclusion of market resources not committed to serving load (uncommitted resources) within the planned Resource Adequacy Assessment analysis. **1.3.1.7** Availability and deliverability of fuel **1.3.1.8** Common mode outages that effect resource adequacy **1.3.1.9** Other environmental or regulatory restrictions of resource availability **1.3.1.11** Resource maintenance outage schedules **1.3.1.12** Sensitivity to resource outage rates and resource capabilities **1.3.1.13** Consider impacts of extreme weather/drought conditions	**R1.4** Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	• Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions were not considered separate from the historical availability characteristics as outlined in Section 3.1.2. • There are no other demand response programs save for those mentioned in R.1.3.1. • Section 3.1: "Emergency Operating Procedures were also included within the model and were available for utilization without incurring a loss of load event." • Section 3.1: "Since prices are high during peak load events and all generators are called on to serve load all resources within the footprint were assumed to be utilized for reliability regardless of load serving obligations." • The affect of resource outage characteristics on reserve margin out outlined in Section 3.2 by examining the difference between the PRM_{LSE} and the PRM_{UCAP}
	R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Section 2.1.4 states that "Transmission maintenance schedules were not included in the PROMOD IV® analysis of the transmission system due to the limited availability of reliable maintenance schedules and minimal impact to the results of the analysis."

Requirements under: Standard RES-501-MRO-02 (Draft_1_v5_081204)	Requirements under: Standard BAL-502-RFC-02	Response
R1.5 Ensure capacity resources located in another Planning Coordinator area and used in this assessment have been documented and such documentation has been provided to that Planning Coordinator.	**R1.6** Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	Sections 2.1 and 2.2 describe the development of the combined representation of generators and the transmission grid through use of a data base, that are the foundation for input into the probabilistic treatment in Section 3.
R1.6 Document that all Load in the Planning Coordinator area is accounted for.	**R1.7** Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	Section 3.1 states that: "Zones 1 through 5 include all load within the Midwest ISO Planning Authority footprint,"
R2 On an annual basis, the Planning Coordinator shall document an assessment of its Resource Adequacy by comparing its load and resource capability for the ten year period in R1.1 expressed as a percentage of the 50:50 probability forecast peak load with the planning reserve margin benchmark in R1.4.	**R2** The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	Table 6 illustrates the load and capability for the Midwest ISO over the next ten years relative to the Reserve Margins calculated in this assessment.
	R2.1 This documentation shall cover each of the years in Year One through ten.	
	R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	
	R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One	Documentation posted with this assessment on February 12, 2010

Appendix D Congestion Based Zones

Utilizing PROMOD Output
To Determine Candidate Zones to Model in GE MARS
In accordance with Module E Tariff and BPM Procedures

Introduction

This document is a starting place from which key text or points may be utilized to develop a final narrative in a section or appendix of the Midwest ISO's 2010 Planning Year LOLE report. The process to conclude zones from an annual PROMOD run has been implemented on three occasions. Those are: a proof of concept demonstration, the 2009 Planning Year LOLE report, and the current 2010 Planning Year LOLE report. High level aspects of the process are defined in the Module E Section 68.1 of the Tariff, and this document is intended to give meaning and substance to that process by using the current data and results for the 2010 PY study. As an overview, keep in mind that determining the zones, and subsequently the import and export limits for them is part of building the LOLE model. This part of the model building process is focused on developing the simplified form network representation required in the LOLE software. That representation is manifested in the model by having multiple zones and quantified transfer capabilities between a zone and a neutral zone (central hub zone) in the LOLE model. Without this aspect the LOLE model would default to one internal Midwest ISO a zone in the LOLE model, and a tie to the external equivalent. Such a "one zone" representation would be equivalent to what has been called a "copper sheet". A copper sheet representation means that no transmission limitations are modeled. In comparison, a copper sheet scenario of the LOLE model would not contribute a congestion adder to the ultimate PRM. In the 2009 LOLE study for example, the representation of multiple zones (non-copper sheet model) accounted for 0.61% of a total 15.40% PRM. In other words, the copper sheet approach that would have ignored congestion would have concluded that a PRM of 14.79% would meet the LOLE criteria. The Midwest ISO Tariff is dedicated to formulating zones driven by congestion throughout the network, versus for example; zones determined by transmission ownership or Load Balancing Area boundaries. In conclusion, while we need to consider the impacts of congestion in building the LOLE model, to date the impact of the network upon the PRM is small (0.61%) compared to major parameters like the forged outage rates of the generation (accounting for 8.49% of the 15.40% PRM) and the uncertainty of the load (accounting for 6.89% of the 15.4% PRM). These quantitative values were taken form Table 6 in the 2009 LOLW report.

Discussion

The scope of the discussion is focused on explaining how the predominantly +MCC areas, -MCC areas or Neutral MCC areas transition from the annual PROMOD output to just reviewing a key peak week of PROMOD output. This narrative is organized about two currently available communication modes. The first being that the discussion will utilize a Q & A format, based on questions from discussions at LOLEWG meetings and the individual comments and shared discussions through e-mail to the Midwest ISO staff involved with the LOLEWG. The second discussion mode is manifested by reference to attached materials, spreadsheets, figures, etc. The most significant of these is a spreadsheet that tracks the zone defining parameter for each of 1,556 geographically mapped busses, from the annual PROMOD output to a key July 19 through July 25 Peak Hours time period. Starting with the Q & A format:

Q1: Why review an annual mapping of the PROMOD output, when it may just add confusion and we are going to end up with a shorter time period, such as a week about the summer peak time?

A1: The annual findings in geographical mapped form have been shared with the LOLEWG in order that they could see the visual starting point in the analysis. The process starts at the annual level in order to confirm which shorter period of time within the year is most related to congestion. The findings to date have supported that the key time is around the peak (see Q3 and A3 for more discussion about the "shorter period of time"). The Tariff is explicit about starting with the annual view of things, and then proceeds to more detailed time periods. Staff needs the broader findings to confirm and track the quality control aspect of the process, reveal anomalies in models, etc. In the 2009 LOLE study for example the modeling tracked network changes phasing in new transmission projects monthly. That effort lead to the conclusion that a summer model of the network is sufficient and the monthly detail was not warranted. As confidence of stakeholders may increase sharing the findings at the broader time frame may not be necessary. Figure 1 from the 2009 LOLE work illustrates how the annual summary of output is used to focus in on a shorter time frame. The individual hourly points within the shorter time frame are shown in Figure 2.

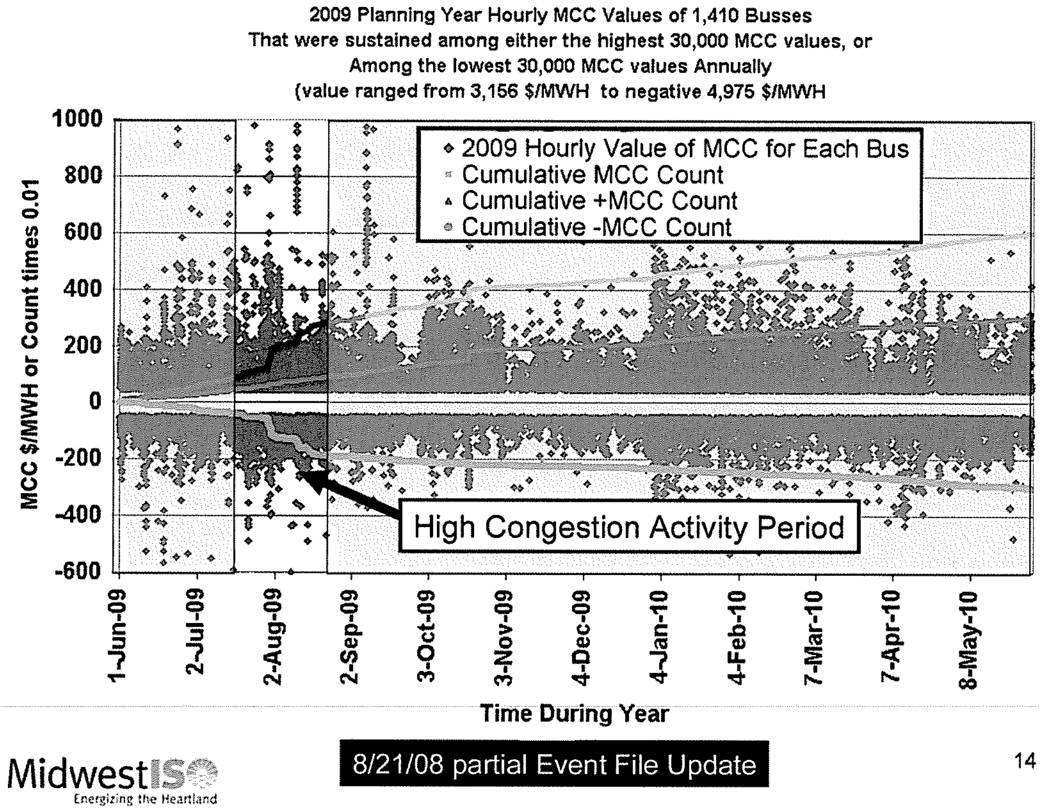


Figure 1 2009 Annual View

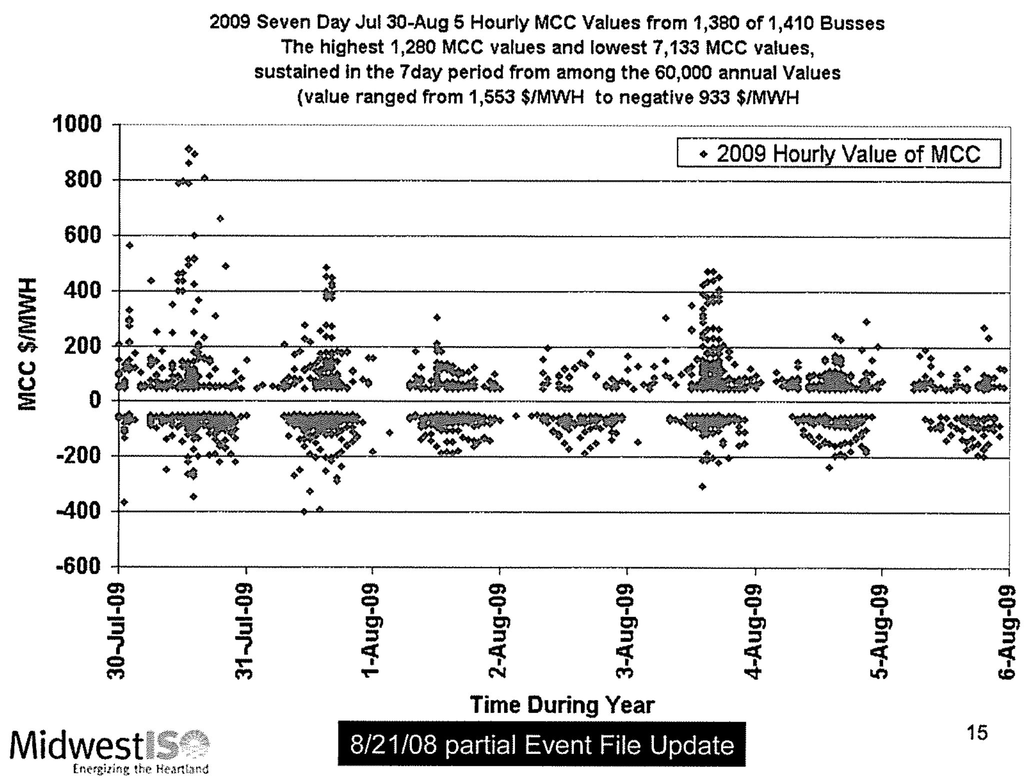


Figure 2 2009 July – Aug 5 Hourly View

Q2: Why is there a +MCC zone emerging in Indiana in the 2010 zone process, and none appeared in the 2009 LOLE study?

A2: The Indiana zone emerged from the 2010 analysis and not the 2009 analysis because of further refinement of the PROMOD event file. The "Petersburg -to- Hanna" 345kv line contingency in the MISO Book Of Flowgates was included in the 2010 analysis and had not been included in the previous the 2009 analysis. The PROMOD event file is constantly being updated and reviewed in many different Midwest ISO stakeholder forms and other various studies. It is this ongoing dynamic interaction with stakeholders and focus studies that allow us to turn out a better product year after year. There was a small indication of +MCC predominance in the "zoomed in" week period 2009 Jul 28-Aug 3 7AM to12AM +MCC and –MCC Summary shown in Figure 3 below. The same area is more active in the 2010 output of Figure 4, and work is in progress to determining if the involved cluster indicated on the MCC buss map is large enough to meet the minimum 2,000 MW of generation or load, to qualify for modeling in the GE MARS LOLE application.

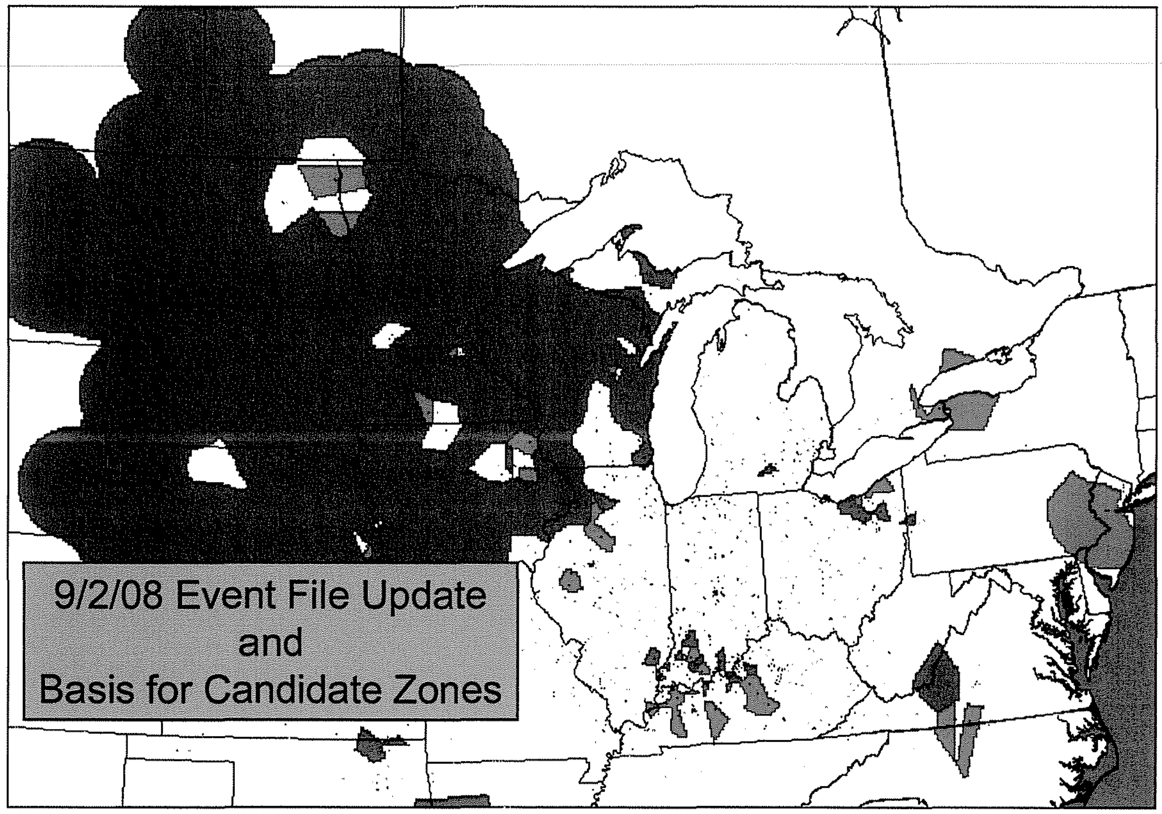


Figure 3 MCC Map Utilized in 2009 Zone Formation Process
2009 Jul 28-Aug 3 7AM to12AM

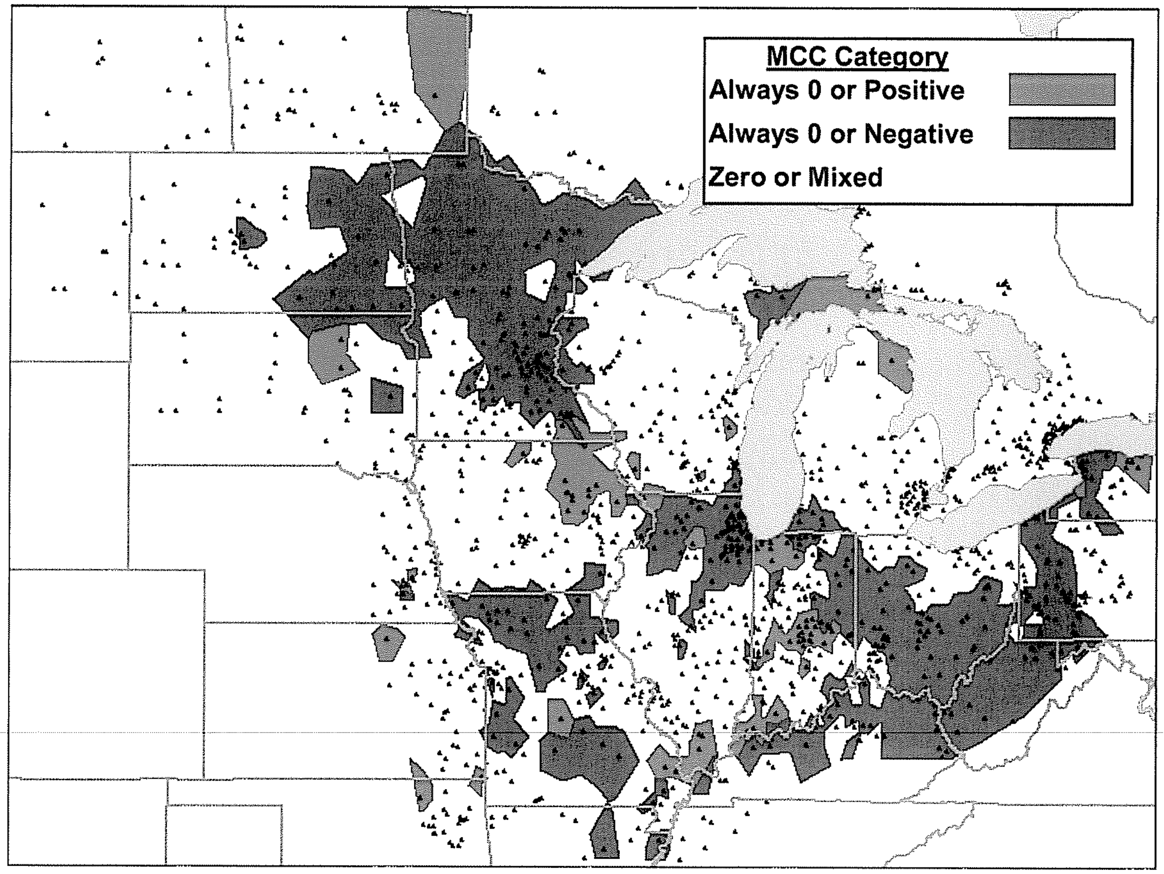


Figure 4 MCC Map being Utilized in 2010 Zone Formation Process
2010 Jul 19 – Jul 25 On-peak Hours

Q3: What are the details about what is going on as the MCC map transitions from the annual view to the zoomed in one week period. Figure 5, the 2010 annual map and Figure 4, the 2010 week long map illustrate the basis of the question.

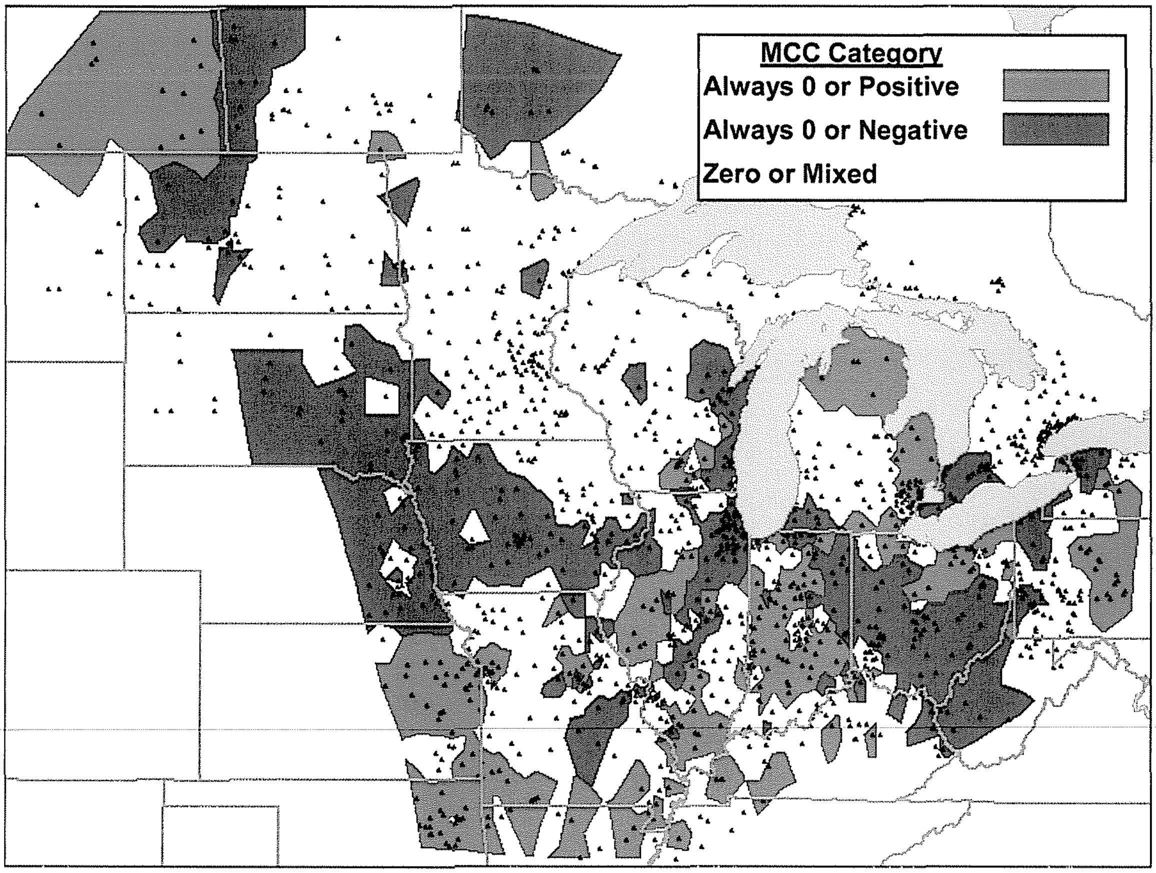


Figure 5 Annual MCC Map of 2010 PROMOD Output

A3: Table 1 is an over view of how the MCC map metrics are changing as smaller time periods are viewed. The smallest time frame possible would be a particular hour, such as the peak load hour. For a single congested hour all busses would fall into three categories:

1. Be among the 30,000 most Positive MCC values (RED)
2. Be among the 30,000 most Negative MCC values (**BLUE**)
3. Not among either of the above and defined as in the Neutral zone (YELLOW)

However rather than one hour, the goal for the LOLE model is to create a more broad or diverse representation of congestion that is generically applicable to some short period of time, such as the peak week for example. Conflicts arise as one attempts to represent a long period of time, such as a year or several months. The requirement for a bus to be called Positive (RED) or Negative (**BLUE**) is for it to have experienced (over the hours in the shorter time period) only same sign MCC values or zero; or absent MCC values in the time period. Therefore, the process seeks a period of time as long as possible, while maintaining at a very minimum, the number of busses that experienced both Positive and Negative MCC values. The end result is that busses are characterized as being consistently or persistently either positive or negative for the given time period. Thus, the metrics of a single hour are spread over as many hours as possible. The reader is encouraged to investigate trends or patterns by applying alternative combinations of Row 10 Column filters in the "Annual to Week Tracked "Tab of the "2010 Annual MCC transition to Jul19 Jul25 PK_072409.xls" spreadsheet. The sheet tracks the classification of each bus as they transition from the annual report to the July 19 through July 25 period. Some shared observations of Table 1 are:

- Shifting occurs as different subsets of the larger set of reported values (large set extracted from the PROMOD run) are analyzed across the shorter specific time period.
- The set for each time period is analyzed for each of the 1,556 tracked buss across the Midwest ISO, to determining if the hourly reported MCC values are mixed with both positive and negative signs (in which case they go into the neutral type) or if the hourly reported MCC values are uniquely of the same sign for the period.
- Column G in Table 1 tracks the number of busses that are declared as neutral due to there being at least one opposing sign for an hourly report in the period. As the time period gets smaller, such neutral busses are likely to transition to Red or Blue, as the occurrence of "neutralizing" opposite-sign MCC values fall outside of the more narrowly defined time period. Unlike the longer time period, a shorter time period therefore becomes associated with busses that:

    - sustain only positive hourly reported MCC
    - sustain only negative hourly reported MCC
    - has fewer busses in the neutral category associated with both positive and negative reported for MCC (less both-sign MCC busses left in the shorter time period).

Similarly, Question and Answers 8 and 9 examine the effects depleting the opposite-sign MCC values by starting with different amounts of annual point than the standard 60,000. Figure 9 is a chart version of Table 1. Q&A

An example of tracking a detail: by applying the filters in Row 10 of the "Annual to Week Tracked " Tab of the "2010 Annual MCC transition to Jul19 Jul25 PK_072409.xls" spreadsheet and counting, reveals that 29 of the 92 +MCC (RED) in the bottom row of Table 1 were (RED) in the original annual summary, and the remaining 63 of the 92 materialized because no negative MCC's were reported for those busses.

- Another finding from analyzing the Row 10 filters is that:
    - None of the Annual Red busses transition to Blue
    - None of the Annual Blue busses transition to Red
    - Busses transition in both directions either between Red and Yellow or between Blue and Yellow. However, and individual bus transitions one way or the other. If a particular bus starts out as neutral in a larger set of MCC value reports it may transition to Red or Blue depending on which sign of MCC reports no longer exist,

and drives it to be exclusively Positive or Negative. If it starts as Red or Blue it can become Neutral if the smaller set of surviving MCC values, no longer contains a report for that particular bus.

- As the "Switched Sign MCC" in Column G in Table 1 are depleted, the most reliable and consistent characterization of the zones is revealed, because on the surface, the view contains fewer undecided busses with both sign MCC values (see Question and Answers 8 and 9 for more detail on Switched Sign MCC as a metric for determining best zone characterization).

Table 1 Summary of MCC Map Quantities versus Time Periods

A	B	C	D	E	F	G	H	I	J
			60,000 MCC Points Annual						
			Number of Busses						
Inclusive Period	Hours In Period	Hourly Buss Data Points	Busses Analyzed for Unique Pos or Neg MCC	Positive MCC	Negative MCC	Switched Sign MCC	Not In 30,000 Positive or 30,000 Negative MCC		Plotted on Map
Annual	All	60,000	1,294	314	451	529	262	=	1,556
July 3 - August 31	All	21,210	1,026	283	571	172	530	=	1,556
July 19 - August 8	All	7,635	827	156	617	54	729	=	1,556
July 19 - August 8	Peak	7,200	822	154	614	54	734	=	1,556
July 19 - July 25	All	2,668	586	95	487	4	970	=	1,556
July 19 - July 25	Peak	2,566	583	92	487	4	973	=	1,556

Q4: Directed to MISO staff: Do you feel the current process adequately captures the important Summer constraint patterns.

A4: Yes, particularly in light of viewing more granular results that provide further understanding. While alternative granular analysis may provide some detail that is not needed, we can use the information to support implementing (or modeling for example) the big picture.

Q5: The analysis starts at an annual level and then becomes more granular as sequential subsets of the annual data are studied. Could starting at the annual level with a finite number (0.4% of all values) of MCC points lead to not capturing important MCC points for the summer period? A different way to ask that question is whether starting with the highest and lowest (30k each) MCC values for just the summer period would end up with the same results. Since the contribution to LOLE occurs primarily in the summer, it would seem that an analysis focused on the MCC values for the critical summer period would be most valuable. Also, the results imply a seasonality to the MCC values as the number of import-constrained busses drop, and export-constrained busses increase, as the analysis gets more granularly focused on the summer peak period. [I think this makes sense from the standpoint that having more resources on-line would help address import constraints (higher-cost units are now dispatched in given load areas decreasing the number of constraints; also more units on-line cause less distant flows to occur.) yet adds to export-constraints (as more resources try to pump out MWs in an area)]. This seems to make it all the more important to focus on, and adequately capture, the summer MCC patterns.

A5: We agree and have found that focusing on the data over a shorter period of time like summer or the peak week provide the better view of what is essential to doing the LOLE study. One approach could be to change the starting point and gather 60,000 data points for example over a shorter period of time. We have investigated gathering more than 60,000 data points over a year and investigated gathering 60,000 data points over a period of time less than a year. We don't feel that the Tariff needs revision to do that sort of analysis. The Tariff is clear that we need to do the Annual 60,000 as a start of the process, and so we view the 60,000 annual data points quantified in the Tariff as performing a required consistent starting point bench mark.

FYI - Technical side comment:

Regardless of size (60,000 or another selection), the busses that fall outside the selection have some hourly MCC value other than zero. Because these busses don't fall into the selected set, the bus locations define portions of the system that will not define a Red or Blue zone, and therefore the boundaries for zones begin to emerge. One would get the similar effect by setting a minimum MCC value for allowing a bus to be in a zone, but rather than set a minimum MCC value, the process ends up with an observed cut off value for positive MCC and negative MCC, that get set dynamically at the price where the positive set of points ends and where the negative set of points end according to the amount of data selected. The message is that the boundaries of zones get influenced by the resulting smallest positive or negative MCC values that make it into the selected size of the set (of 60,000 for example). This is comparable to not including the busses that are far removed from the active congestion on the system, a treatment similar to setting a generator shift factor cut off or power transfer distribution cutoff limit in various planning applications. Otherwise any non-zero MCC value, regardless of how small it's influence could drive a zone boundary very far from the predominant area of an emerging candidate zone. Zone boundaries are a geographic parameter, whereas zone size (amount of load or generation MW) is a different parameter.

In the 2010 cycle of LOLE study we have observed that on an annual basis that the 60,000 values we are keeping, contain lower $/MWH values in the 2010 study than the MCC values screened out in the 2009 study. The lower $/MWH values indicate that we are keeping some "not so reliability pressing" congestion data. We investigated this effect. For comparison Figure 6 illustrates what would happen for the peak week period if we started with fewer points annually at

30,000 for both positive and negative. Figure 7 is our base case at 60,000 points annually for the Jul19-Jul 25 week. Figure 8 represents keeping about twice an many points for the Jul19-Jul 25 week. Figure 8 evolved from keeping 60.000 over a 3-month period versus the annual, before zooming down to the on-peak hours of the Jul19-Jul 25 week. The tables at the top of each map include the metrics consistent with the metrics for the base case in the bottom row in Table 1. For example the numbers of busses contributing to the evaluation are respectively 1535, 2566, and 5306. The column headed "Switched Sign MCC" has a count of 90 in Figure 8 which is much higher than the 3 in Figure 6 and 4 in Figure 7. The answers to Questions 7, 8 and 9 go into more detail about the "Switched Sign MCC", and address a metric for determining what sample size of selected points might most appropriately reflect a zonal picture. By collecting 60,000 points over a shorter period of time, lower absolute valued $/MWH points were retained and served to keep more opposite sign reports. Aside from the number of busses reporting values; as was varied across Figures 6, 7 and 8; we also took a second pass at specific areas during the Jul19-Jul 25 week and collect the data for all busses, to get detailed information for the model building. We have a ability to represent all busses over a limited area, like one state for example, and are not able to do that for the whole system. The special look at the "all bus" version in specific areas of the system facilitates building the zones much more accurately, but not all areas warrant that detail review.

			30,000 MCC Points Annual						
			Number of Busses						
Inclusive Period	Hours In Period	Hourly Buss Data Points	Busses Analyzed for Unique Pos or Neg MCC	Positive MCC	Negative MCC	Switched Sign MCC	Not In 15,000 Positive or 15,000 Negative MCC		Plotted on Map
July 19 - July 25	Peak	1,535	438	38	397	3	1,118	=	1,556

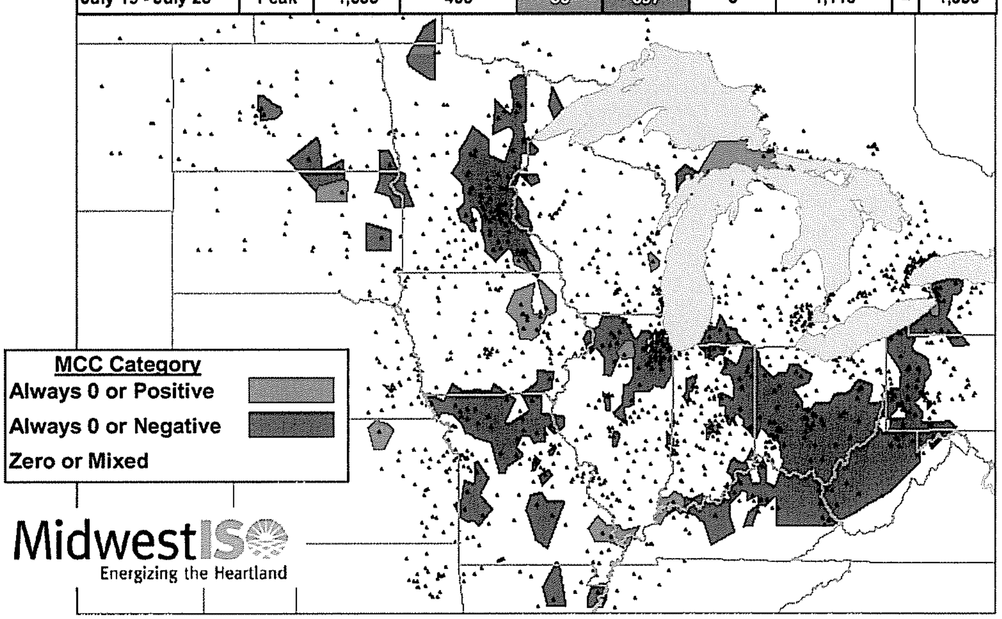


Figure 6 Starting with only 30,000 total points annually

And drill down to the peak week

			60,000 MCC Points Annual Number of Busses						
Inclusive Period	Hours In Period	Hourly Buss Data Points	Busses Analyzed for Unique Pos or Neg MCC	Positive MCC	Negative MCC	Switched Sign MCC	Not In 30,000 Positive or 30,000 Negative MCC		Plotted on Map
July 19 - July 25	Peak	2,566	583	92	487	4	973	=	1,556

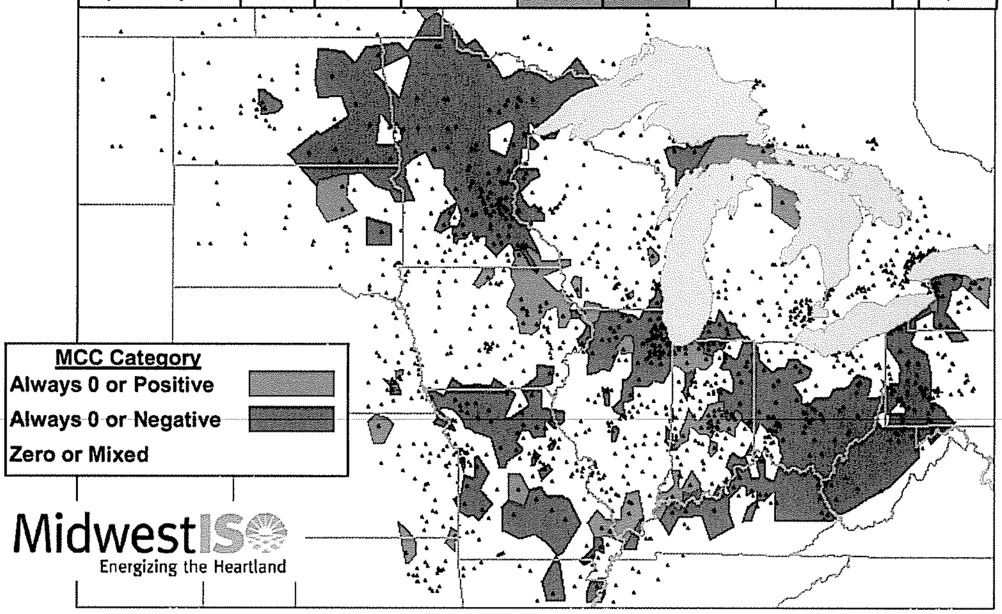


Figure 7 Starting with the 60,000 total points annually And drill down to the peak week

			60,000 MCC Points Over 3-months Number of Busses						
Inclusive Period	Hours In Period	Hourly Buss Data Points	Busses Analyzed for Unique Pos or Neg MCC	Positive MCC	Negative MCC	Switched Sign MCC	Not In 3-month Window of 30,000 Positive or 30,000 Negative MCC		Plotted on Map
July 19 - July 25	Peak	5,306	970	427	453	90	586	=	1,556

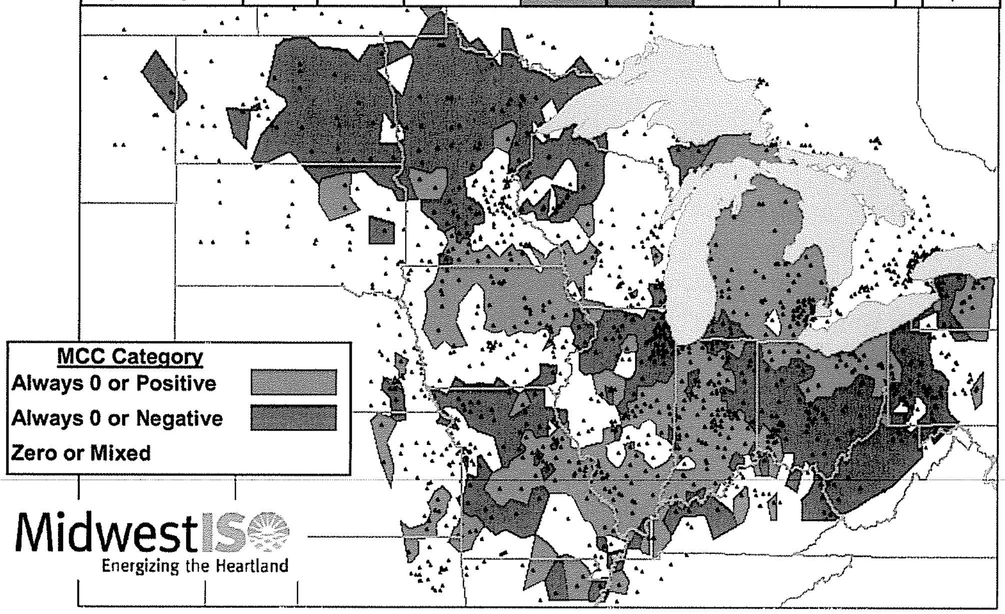


Figure 8 Starting with 60,000 total points over three months June, July, and August and drill down to the peak week

Q6: Does the analysis include any or enough draws? Isn't congestion in MISO often an event-driven outcome? Are sufficient data points generated in the analysis to get to reasonable results?

A6: All events in the event file are evaluated for all 8,760 hours in the PROMOD run. One generation outage draw is applied, the PROMOD run does not do probability analysis on additional outage draws like is implied in the subsequent GE MARS phase. We think the process is achieving what we want it to, as explained in the introduction paragraph. We have not run alternative PROMOD draws which can vary from one year to the next. While such a targeted study may reveal some impact on zone formation, it would only cause the modeling of slightly different zones. When modeled in GE MARS for 2009 for example, slightly different zones would not likely impact the sole essential determination that congestion has a 0.61% contribution to the 15.40% PRM. Other tests in the process assure that if a specific load zone (red zone) has a marginal combination of generation capacity and equivalent tie line capacity, a detailed review apart from the PROMOD draw is undertaken. Furthermore, there is no risk that entities with load in a particular zone will be faced with a different PRM. Consistent with the stakeholder process (which has included addressing a particular key point raised at an LOLEWG); Tariff re-wording has been implemented and is under way in the clean up filing to clarify that for the first year of every planning cycle, all zones get the same PRM. It is only the contribution that congestion has upon the PRM (i.e. the 0.61% of 15.40% in 2009 for example) that is affected by modeling the zones differently. Midwest ISO staff is most interested in observing how the "0.61%" may change over time and the driving factors.

Q7: Do you think the design of the methodology allows the results to be arbitrarily influenced? For example, the current analysis starts with 60k data points (0.4% of total). What if 100k data points were used? On one hand this could increase the number of positive busses only because more busses are included in the 100k sampling, but on the other hand there are now more hours where one opposite-sign MCC value could "transform" the positive buss to neutral. What if the analysis started with 30k data points? If a simple change in the sampling size leads to changes in the results, and that seems somewhat likely with this methodology, then the methodology is suspect. Our results should not be dependent on sampling assumptions, especially if the starting sample size is somewhat arbitrary.

A7: We know from analyzing historical congestion that a majority of congestion occurs only 1% of the time. This implies a close correlation to LOLE which is also driven by what happens over a relatively few key hours during the year. Regarding the sensitivity of one or the absence of one opposite sign data point biasing the whole thing, we see it this way. If one looks at the whole year, that is exactly the "mixed bag" that you are dealing with. In other words the annual situation has a lot of Switched Sign MCC busses. However, when you deal with the more essential peak week period for example the category of "Switched Sign MCC" essentially goes away. The vast majority of the remaining data is purely Positive, Negative, or Neutral and the issue of busses with both positive and negative becomes moot, because they become greatly minimized during that smaller time frame. Figure 6 illustrates the declining category of neutral busses that got defined by analysis, from Column G in Table 1.

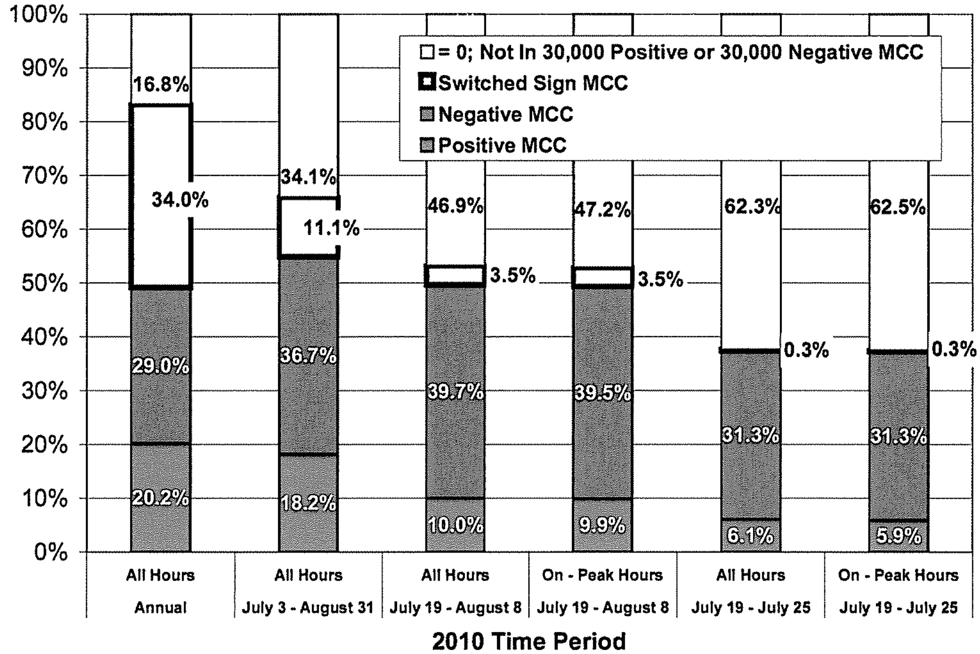


Figure 9 Utilization Mix of 1,556 Buss Plotted versus 2010 Time Period
Values for the charted percent of busses in categories are from Table 1

Q8: Does the methodology need to incorporate more of a statistical assessment? If I understand the process correctly, a single opposite-sign MCC value would cause a bus to be determined neutral. If a buss had 50 extreme high MCC values and only 1 low value, it would be considered neutral. Should it? At the same time, a bus with only one positive MCC and no negative MCC hours would be deemed positive. Should it? Wouldn't a statistical threshold work better to identify positive and negative MCC busses?

A8: The answer to Question 7 speaks to the "single opposite-sign" portion of the question. Regarding the statistical approach, the process is designed to be simple and consistent without the implications of high level statistical approaches. Because the amount of output from the PROMOD can be very large, analyzing that output alone is somewhat statistical. Therefore, the process capitalizes on that large amount of output and places the performance of each bus over selected time periods into three buckets:

1. MCC value is always Positive or absent (or referred to as "zero") from the retained data for the analyzed period
2. MCC value is always Negative or absent (or referred to as "zero") from the retained data for the analyzed period
3. The third bucket of Neutral busses is due to:
    a. mixed positive and negative signs in the output (Switched Sign MCC data points), or
    b. by not having a reported value sustained from the top most positive or bottom most negative set extracted from the

PROMOD run, or values from the set that do not exist in shorter periods that are analyzed. For example, we have plotted the annual positive, negative, and neutral results to comply with the tariff, track the process and gain understanding of what is happening. However we feel that the annual results or any shorter period that has substantially remaining values in the Neutral category due to having both positive and negative reported values, is not a mature set or represents a lower quality representation of the big picture. The process seeks the "period of focus" to the point where there is essentially no impact from busses that are sometimes positive and sometimes negative. Also see the answer to Question 7 as referenced to Figure 9 where the neutral busses that were driven by the opposite sign rule are weeded out, as one moves to the more important peak hours of peak week time frame.

Figure 10 illustrates another perspective of how the "period of focus" is affected by alternative starting points of data different than the 60,000 annual basis. Figure 10 illustrates two points:

1. The plot in Figure 6 can be improved by having more data to start with, because there is clear indication that taking on additional data points, evident in the base 60,000 annual case, will still allow satisfying the condition of weeding out the neutral busses due to the PROMOD reporting both positive and negative values and still allow more information to drive the picture of things.
2. Figure 10 also supports that the plot in Figure 8 does not represent the matured plot appropriate for the July 19 – July 25 period, because it still contains results that contain too many neutral busses (count shown the Figure 10) driven by both positive and negative values. In order to apply the starting point of 60,000 points over a three month period; either a smaller period of focus would be appropriate. Alternatively, to sustain the July 19 July 25 period of focus, the data for Figure 8 would need to be reduced from the 60,000 starting point over three months by retaining fewer points, until the use of both positive and negative values is weeded out further.

If one engages in a process that retains large amounts of busses with both positive and negative reports in the final utilized period of focus, then statistics would become necessary, and various complex rule making schemes or statistics would be necessary to "divide the baby" ("divide the baby" meaning resolve what to do with busses that have both positive and negative reported values based on the relative amounts of each). The present process under the Tariff and BPM applies a simpler approach where the appropriate period of focus is sought, where (except for relatively very few busses) the questionable busses with positive and negative values fall out of the process and are not utilized or impact the results for the period of interest. In a sense, the resulting plot is as "locked in" as a one hour snapshot of values, where there would only be Positive, Negative; while having small Positive and Negative MCC's values defined as Neutral (small MCC value correlating to that the buss is too far away from the influence of the prevailing flowgates under congestion to warrant tracking). In effect a one-size-fits-all single-hour construct suitable for the GE MARS model, is found that applies to all the peak hours in a week.

Figure 11 shows the relationship between the number of busses utilized in the July 19 – July 25 period (surviving from the PROMOD, the specified retained, top thousands and bottom thousands of values) versus the number of Switched Sign MCC busses remaining. The remaining "Switched Sign MCC" is the metric that has been identified by Midwest ISO subject matter experts, that correlates to "noise" or misinformation in the plotted maps. Previously, subject experts that needed to relied more extensively on experience and engineering judgment to determining the acceptance or suitability of a specific plot for zones, have concluded that greatly minimizing the Switched Sign MCC count correlates greatly to determining the best reflection of the zone clusters. Therefore, the extent to which depletion of Switched Sign MCC values can be achieved, can be used to determine if a plot is suitable for defining candidate zones.

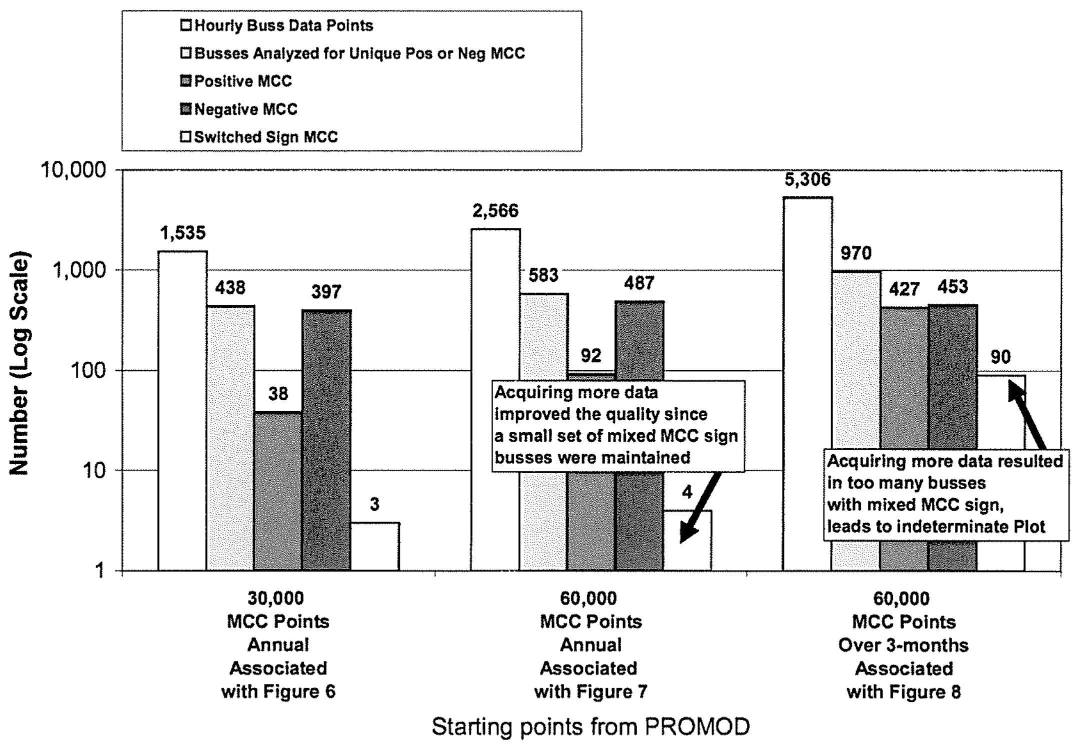


Figure 10 Points and Busses used Versus Number of Starting Points July 19 through July 25

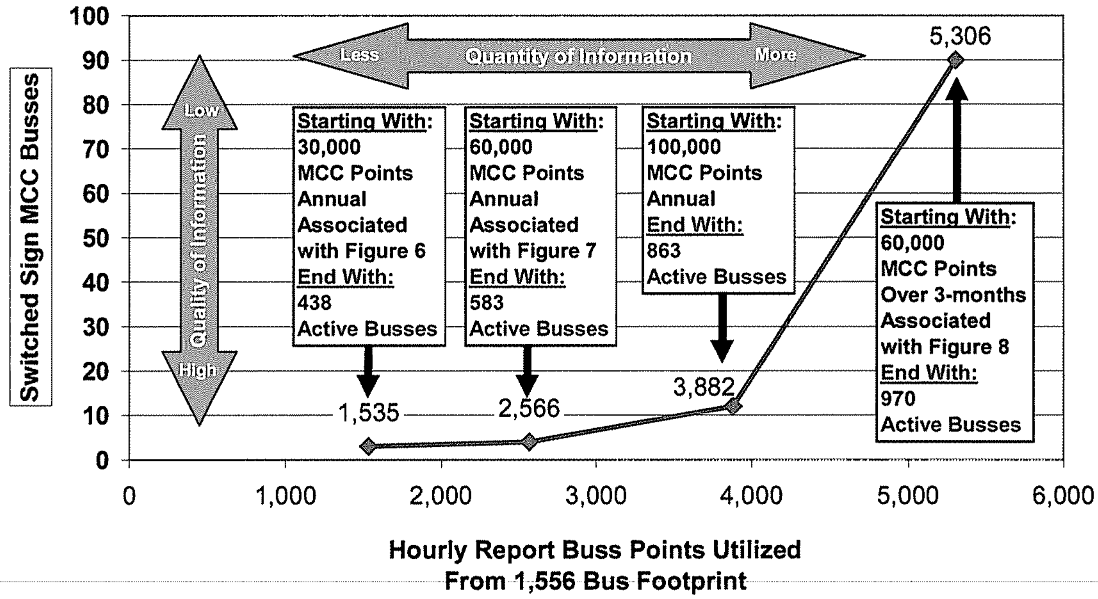


Figure 11 Number of Hourly Report Buss Points and Active Busses Utilized Versus Number of Remaining Switched Sign MCC Busses For the Period July 19 through July 25 Peak Hours

Q9: It is interesting that the buses with negative MCCs (export zones) increase rapidly in the summer months while the positive MCCs (import zones) seem to increase nearly linearly all year. The import zones might need emergency imports to sustain 1 day in 10 years LOLE and if import capability is limited, then the zone will experience more than the target LOLE. Conversely, if the export limited zones need to utilize emergency imports, the import capability should be there because the export limited zones are by definition not import limited. Is it appropriate to define LOLE zones based on a high congestion period that is driven by export limits? Aren't we really concerned with import limits?

A9: There are two parts to this answer:

1. The system is being studied for the appropriate Planning Reserve Margin, and there has been general agreement previously that studying the system for Summer conditions will provide adequate PRM during the balance of the year. The main driver is that LOLE accumulates primarily over one summer month.
2. If an import limit were an issue during the summer, the urgency for that will be supported by it showing up in the results after the annual data points are cropped down for the shorter time period (i.e. July 19-July 25 in the case of the 2010 LOLE study). The showing of either sign type of zone in the annual data does not indicate an answer at that point in the analysis because of the multitude of busses with both positive and negative MCC

values (as discussed in Answer 8 regarding the need to deplete Switched Sign MCC busses). A suitable view of the situation is only revealed when the data is condensed down (or match to cover a time period) such that Neutral busses no longer exist (or are greatly minimized) that are driven by having both positive and negative MCC sign points. This condensing down of the annual data to a smaller time period to a point where there are very few Neutral busses determined by remaining data points with positive and negative MCC signs, is the scope of Answers 7and 8. The results are indicating that import is not emerging as an issue, and aggregate deliverability is emerging as the driver for influencing the PRM. We monitor for both relevant import and import limits, but the import limits are currently revealing no concern, as they are not driving the LOLE in particular areas or across the system. If import is an underlying problem in the network, we believe we have demonstrated that the process will respond accordingly and show that effect.

Q10: Does splitting the buses up into positive and negative MCCs really show the reliability-based congestion picture? For example, does a bus with an MCC of +20 $/MWh really belong in the same "bucket" as a bus with a +50 $/MWh MCC? It seems that the MCC difference between the two MCC buses is an indication of congestion between them. Perhaps we should really focus on the MCC *spread* between buses. Even two buses with negative MCCs can have congestion between them if the spread is significant.

A10: It is only the sign of the MCC that is relevant to reliability, because that is the indicator that congestion is occurring regardless of price. Congestion would be indicated between two opposite MCC sign busses. The sign indicates the direction of congestion and conveys part of the information needed to construct the ties among zones modeled in the LOLE probabilistic application. That is why the process focuses on the MCC sign rather than the total LMP. The difference in MCC magnitude is only an indication of a "would be" economical optimum re-dispatch based on total LMP, or how distant (smaller MCC being electrically farther away from the prevailing congestion). The driving buss locations on the system are calling for generation to increase in some places, and at the same time decrease in other places. MCC magnitude screening is done to extract only the most positive and most negative MCC values to start the analysis. These largest magnitude MCC's, are the choice to correlate to times when the congestion is most likely to be approaching a reliability issue. Retaining the lower value MCC's correlates to a more casual redispatch situation that is less likely to imply that here are no additional units to commit (a reliability concern) to the redispatch process. While the LMP economic incentive to change generator output may vary, that only reflects the difference in signaled incentive to accomplish the redispatch. The fact that the redispatch signaled up versus down at different geographic locations (more specifically different electrical network topological locations versus the actual GPS geographic location) is the aspect being recognized for reliability needs. The congestion from a flowgate or a collection of flowgates simultaneously determines the extent to which power can be transferred among zones. The limit to transfer gets quantified in a later step. The subsequent PROMOD step that determines the Effective Export Import Tie Capability (EETC) or the Effective Import Tie Capability (EITC), quantifies that limit for use in defining limitations among zones modeled in the LOLE probabilistic model.

Appendix E Wind Capacity Credit

A Wind Capacity Credit of 8% of the Registered Max capacity of wind resources was set by the Midwest ISO for the Planning Year 2010. The 8% value was based on calculating the ELCC over 5 historical years and aligning those results to a trend. The specific value applicable for the expected 7.0% penetration in PY 2010, was then computed from the trend line as illustrated in Figure E3. Table E1 is a listing of the Wind Output at time of 40 Daily Peak loads over the past 5 years. Figures E1 and E2 compare the intermittent nature of the Wind resource relative to other metrics, like load and commitment properties of dispatchable resources.

Table E1 - Wind Output at Time of 8 top Daily Load Peaks

EST START_TIME of Daily Peak	Wind Registerd Max (MW)	Last Hour of the Day Hourly Output % of Registered Max	Output % of Registered Max at Daily Peak Load	Daily Peak Load (MW)	Year	Planning Year Peak Rank
8/3/05 16:00	908	41.1%	11.5%	109,473	2005	1
8/2/05 16:00	908	31.9%	23.2%	109,099	2005	2
7/25/05 15:00	908	43.0%	9.8%	108,558	2005	3
8/9/05 16:00	908	7.1%	31.1%	107,615	2005	4
8/1/05 17:00	908	15.5%	6.4%	106,949	2005	5
6/27/05 15:00	908	18.7%	32.1%	105,353	2005	6
7/21/05 16:00	908	1.8%	10.2%	104,998	2005	7
8/8/05 17:00	908	50.1%	43.6%	104,011	2005	8
7/31/06 16:00	1,251	29.7%	56.0%	113,095	2006	1
8/1/06 16:00	1,251	25.5%	11.1%	110,947	2006	2
8/2/06 16:00	1,251	4.3%	2.9%	110,499	2006	3
7/17/06 16:00	1,251	19.1%	34.4%	110,011	2006	4
7/18/06 16:00	1,251	48.2%	5.1%	102,742	2006	5
7/28/06 16:00	1,251	45.1%	37.6%	102,161	2006	6
7/19/06 16:00	1,251	34.0%	30.2%	101,744	2006	7
7/25/06 17:00	1,251	12.5%	4.3%	100,948	2006	8
8/8/07 16:00	2,065	1.9%	2.1%	101,800	2007	1
8/1/07 16:00	2,065	7.8%	3.1%	101,496	2007	2
8/7/07 17:00	2,065	5.2%	2.9%	101,306	2007	3
8/2/07 16:00	2,065	4.1%	2.2%	101,268	2007	4
7/31/07 17:00	2,065	23.2%	17.0%	98,955	2007	5
7/9/07 15:00	2,065	9.9%	2.2%	98,049	2007	6
8/6/07 17:00	2,065	6.1%	3.7%	97,435	2007	7
6/26/07 15:00	2,065	15.4%	17.6%	97,413	2007	8
7/29/08 16:00	3,086	9.5%	12.5%	96,321	2008	1
7/16/08 16:00	3,086	22.6%	14.8%	95,982	2008	2
7/17/08 16:00	3,086	13.7%	13.7%	95,592	2008	3
8/1/08 16:00	3,086	22.9%	13.1%	93,422	2008	4
7/18/08 16:00	3,086	14.5%	3.1%	93,144	2008	5
8/5/08 16:00	3,086	9.9%	6.9%	93,089	2008	6
7/31/08 17:00	3,086	4.5%	13.0%	92,544	2008	7
8/4/08 17:00	3,086	5.7%	5.8%	92,245	2008	8
6/25/09 14:00	5,636	9.2%	1.4%	94,185	2009	1
6/24/09 17:00	5,636	6.6%	5.9%	92,402	2009	2
6/23/09 15:00	5,636	15.0%	12.0%	91,671	2009	3
8/10/09 14:00	5,636	5.3%	2.9%	89,039	2009	4
6/22/09 16:00	5,636	8.9%	9.4%	87,846	2009	5
6/26/09 16:00	5,636	34.8%	19.2%	87,355	2009	6
8/14/09 16:00	5,636	42.6%	37.3%	87,023	2009	7
8/17/09 15:00	5,636	28.0%	19.9%	85,593	2009	8

Availability Distribution of Wind versus
Avaliability of Dispatchable Fleet Capacity
At time of 8 Top Daily Peaks in each of last 5 Years

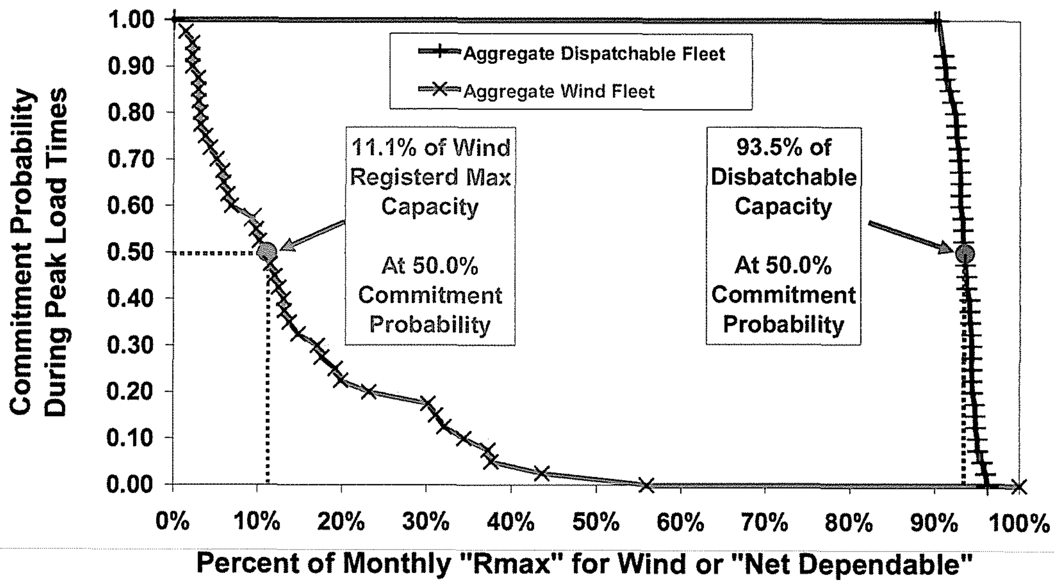


Figure E1 – Charted Wind Values from Table E1
And Dispatchable Fleet values extracted from GADS data base
At Historical Daily Peak Load times in Table E1

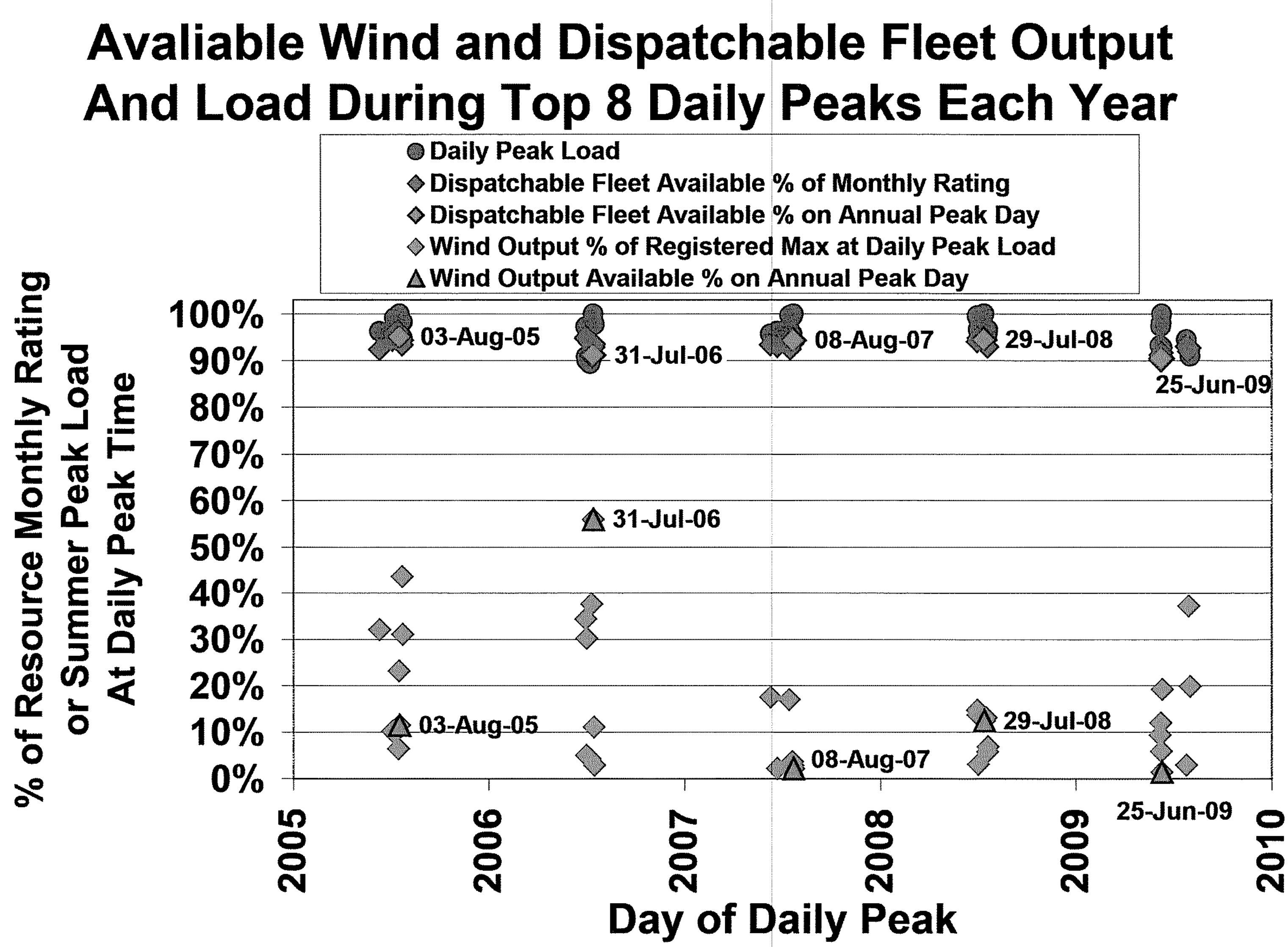


Figure E2 – 5 year Historical Variability of Wind Fleet Dispatchable Fleet and Daily Peak Load

Table E2 – 5 Historical Years of ELCC for Wind and Simulated Higher Penetration levels utilizing the same historical Wind and Load Patterns

Market-wide Operational Tracking			After-The -Fact ELCC % and Penetration %			ELCC % with Wind Resource Pattern Simulated at Increased Penetration					
						10 GW Penetration		20 GW Penetration		30 GW Penetration	
Peak Load (MW)	Planning Year (PY)	Registered Max MW Capacity (RMax)	MN Wind Int. Study Emulated Annual	**Midwest ISO ELCC**	Historical Penetration 3	ELCC%	Penetration %	ELCC%	Penetration %	ELCC%	Penetration %
n/a	2003		20.1%								
n/a	2004		11.9%								
109,473	2005	908	5.1%	**16.7%** [1]	0.7%	14.3%	7.9%	12.8%	15.8%	11.9%	23.7%
113,095	2006	1,251	n/a	**39.6%**	1.0%	23.5%	7.7%	15.0%	15.3%	11.6%	23.0%
101,800	2007	2,065	n/a	**2.8%**	1.8%	2.6%	8.5%	2.6%	17.0%	2.6%	25.5%
96,321	2008	3,086	n/a	**12.8%**	2.8%	12.9%	9.0%	12.4%	18.0%	11.6%	27.0%
94,185	2009	5,636	n/a	**3.1%** [1]	5.2%	2.8%	9.2%	2.6%	18.4%	2.3%	27.6%
110,625	2010	**9,000**	n/a	**n/a**	7.0%	< - - - Forecasted 2010 Penetration					

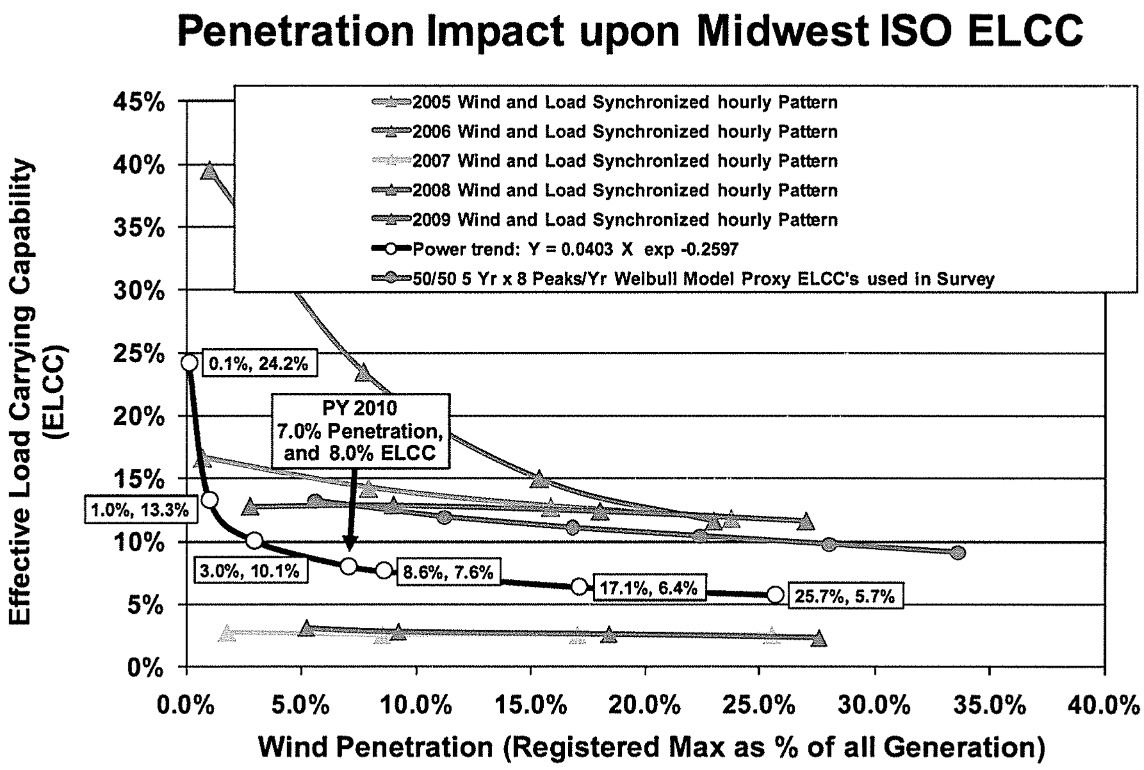


Figure E3 – Charted Values from Table E2, 5 Historical Years of ELCC for Wind and Simulated Higher Penetration levels utilizing the same historical Wind and Load Patterns (Also, Including Proxy Characteristic ELCC (Red series) used in survey Figures E4 and E5)

Prior to the final calculation ELCC results in Table E2 and determination of Wind Capacity Credit by a trend line approach as depicted in Figure E3, a survey was sent out to the Loss of Load Expectation Working Group (LOLEWG) mailing list to obtain feedback regarding opinions on how the pending ELCC results might be utilized in setting the Wind Capacity Credit for Planning Year 2010. The mailing use two versions of charted proxy ELCC results as a back drop for requesting comments. Figures E4 and E5 are the two proxy charts use in the survey. For comparison to what ended up as the applied ELCC curve (black series) in Figure E3 for PY 2010, Figure E3 also shows the range for the proxy ELCC values (red series) utilized in the survey. The demonstration values for ELCC versus penetration depicted in Figures E4, E5 and E6 were generated from loss of load runs that used an un-calibrated probabilistic model of the wind fleet generation (i.e. the wind model had not yet been bench marked to actual ELCC runs based on wind patterns). The 5 proxy questions (with Figures and Table references updated for this Appendix E) and a summary of October 2009 survey answers follow these charts.

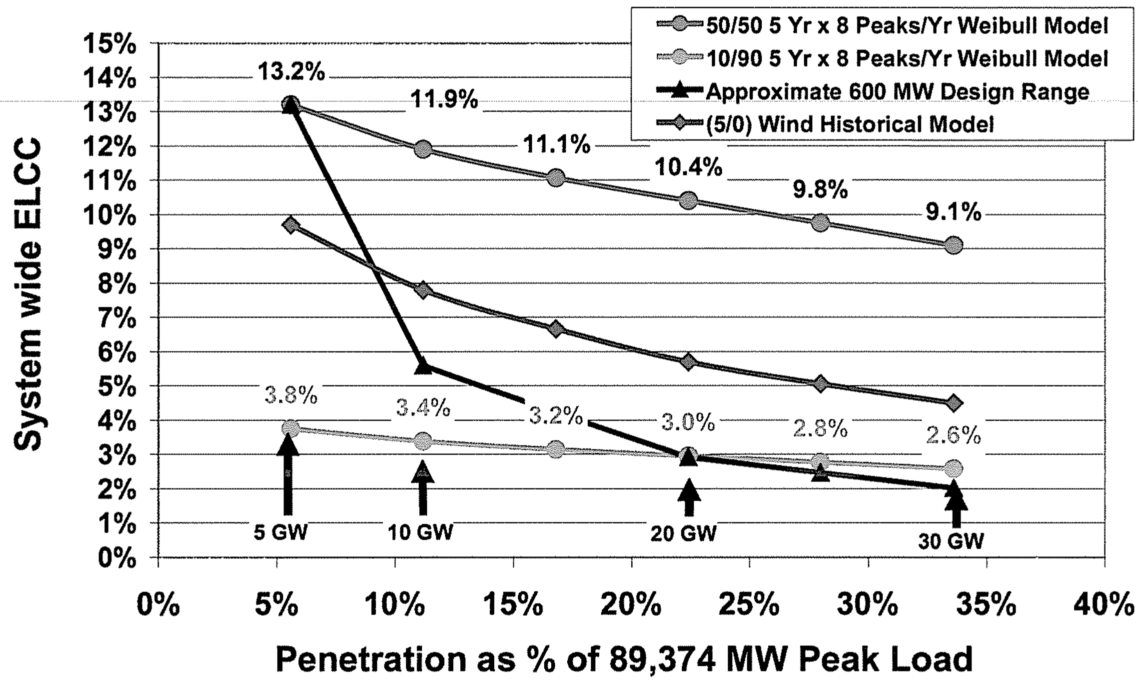


Figure E4 – Proxy Effective Load Carrying Capability (ELCC) of Wind As a Percent of Registered Capacity Versus The Penetration of Registered Capacity as a Percent of Peak Load

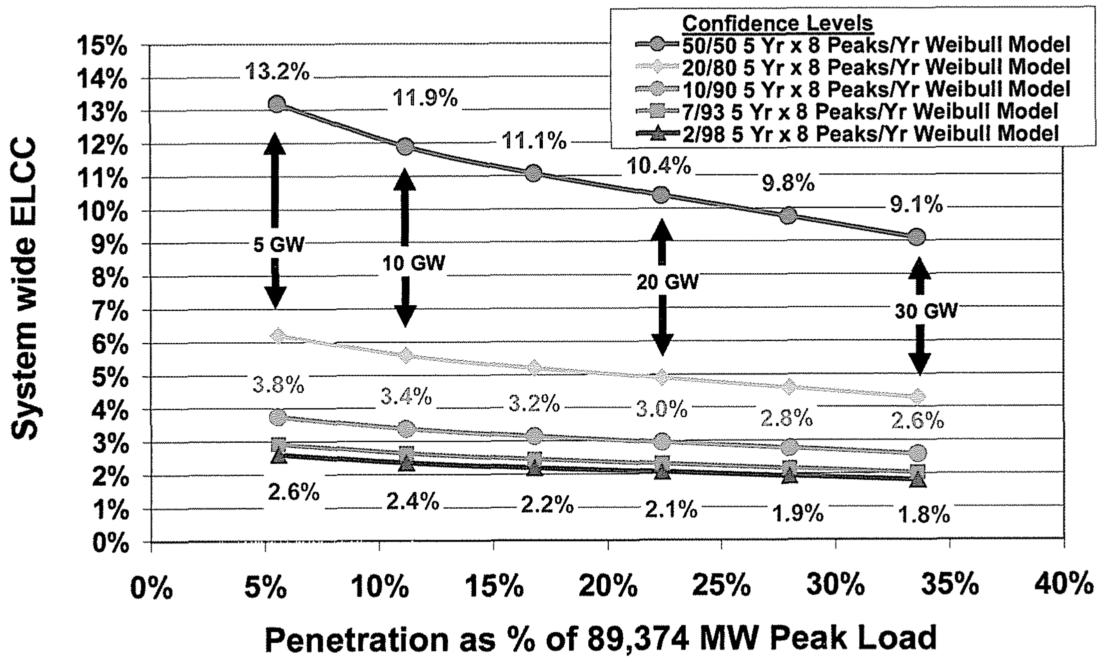


Figure E5 – Proxy Effective Load Carrying Capability (ELCC) Of Wind as a Percent of Registered Capacity versus the Registered Capacity Increasing in Penetration as a Percent of Peak Load across a Range of Confidence Levels

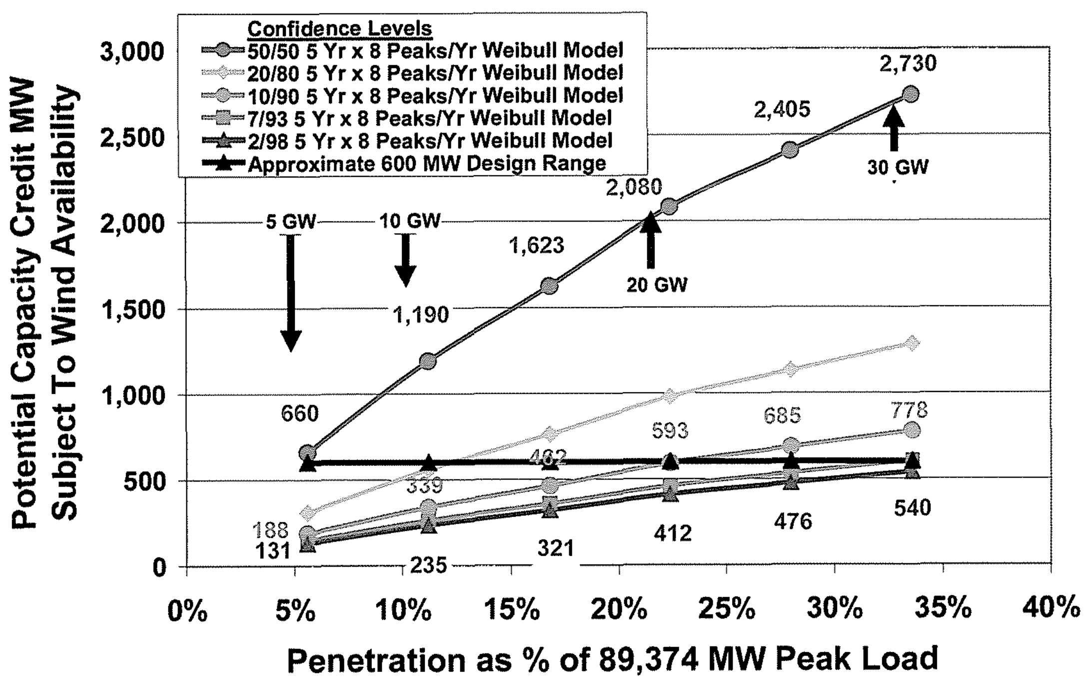


Figure E6 – Proxy Megawatts of Wind Capacity Credit Realized at Risk For associated Confidence Levels versus the Registered Capacity Increasing in Penetration as a Percent of Peak Load across a Range of Confidence Levels

Table E3 – Capacity Credit
By Applying a Probabilistic Model in LOLE Analysis
(Wind pattern basis of ELCC was pending in Table E3, as seen below as of October 2009)

Post Market Wind Resource	Wind Penetration MW 5,000	10,000	20,000	30,000	
Average hourly Capacity Factor	26.9%	26.9%	26.9%	26.9%	Historical Data
Jun-Aug Average Capacity Factor at Daily Peak Load	14.8%	14.8%	14.8%	14.8%	
Jun- Aug Median Capacity Factor at Daily Peak Load	11.3%	11.3%	11.3%	11.3%	
Pre-2010 Capacity Credit % / MW	20% / 1,120 MW	N/A	N/A	N/A	
50/50 Weibull Distribution Median	9.79%	9.79%	9.79%	9.79%	Two Confidence Levels In Wind Density Function *
10/90 Weibull Distribution Median	2.79%	2.79%	2.79%	2.79%	
50/50 Confidence Capacity Credit %	**13.2%**	**11.9%**	**10.4%**	**9.1%**	MARS Run 50/50 Confidence Level Results
50/50 Confidence Potential Capacity Credit MW	660	1,190	2,080	2,730	
20/80 Confidence Capacity Credit %	**6.2%**	**5.6%**	**4.9%**	**4.3%**	MARS Results Adjusted for Different Confidence Levels
20/80 Confidence Potential Capacity Credit MW	310	559	977	1,283	
10/90 Confidence Capacity Credit %	**3.7%**	**3.3%**	**2.9%**	**2.5%**	
10/90 Confidence Potential Capacity Credit MW	185	333	582	764	
7/93 Confidence Capacity Credit %	**2.9%**	**2.6%**	**2.3%**	**2.0%**	
7/93 Confidence Potential Capacity Credit MW	147	264	462	606	
2/98 Confidence Capacity Credit %	**2.6%**	**2.4%**	**2.1%**	**1.8%**	
2/98 Confidence Potential Capacity Credit MW	131	235	412	540	
600 MW Design Range Capacity Credit %	**13.2%**	**5.6%**	**2.9%**	**2.0%**	Selected MARS Results At Constant Design MW Senarios
600 MW Design Range MW	660	559	582	606	
1,000 MW Design Range Capacity Credit %	**19.8%**	**11.9%**	**4.9%**	**4.3%**	
1,000 MW Design Range MW	1,000	1,190	977	1,283	

*** see Table E4 for all Confidence Level Density Function values that are used in the balance of Table E3**

Table E4 Confidence Level Scenarios
(Note: half of the output observations occur below the 10% level)

Range of Confidence Values		
Confidence Level	Output % of Registered Max. X-Axis Confidence Levels Fig 5 and Fig 6	Cumulative Probability
50/50	9.79	0.500
20/80	4.60	0.200
10/90	2.79	0.100
7/93	2.17	0.070
2/99	1.94	0.059

Leading Questions used in October 2009 survey sent to LOLEWG e-mail list, for feedback to the Midwest ISO:

Overall, general comments of respondents confirmed earlier information exchanges such as those at the LOLEWG, Wind Integration workshops, and direct contact with power suppliers that:

- The determination of wind capacity should be technically based and linked to Loss of Load Expectation, and the Effective Load Carrying Capability (ELCC) method is most widely accepted.
- Parties expressed desire to move from a system wide wind capacity credit to one that could distinguish different capacity credit geographically. The Midwest ISO plans to have more granular credits starting in Planning Year 2011.
- Most parties recognize that the currently applied 20% credit is likely to be too high compared to the expectations of what a more rigorous method would determine. Expectations start at about the 11% level and range downward.
- There is a desire to make the treatment of Wind Capacity as consistent as possible with the treatment of conventional dispatchable resources.

The eleven responding parties to the questions were:

NREL – National Renewable Energy Laboratory
WOW and AWEA – Wind on the Wires and American Wind Energy Association
Xcel Energy
Consumers Energy Company
Indianapolis Power & Light Company
Great River Energy
Madison Gas & Electric
Duke Energy
Detroit Edison
ITC Holdings Corp.
Wisconsin PSC (staff member)

1) Your thoughts on basing the wind capacity credit on a more likely to happen basis like the 50/50 confidence level versus warranting more conservative 7/93 level, for example, as illustrated in Figure E5 and Table E3

   Response: Among the six that responded, four concurred with the 50/50 and two suggested a more conservative approach for now.

2) If you had to pick a less likely path, which one below the 50/50 confidence level, in your view is most appropriate (i.e. the 2/98 confidence level or another as shown in Figure E6 and Table E3)?

   Response: Among the five that responded, comments ranged form on at sustain 50/50 to most conservative at10/90 confidence. Some conditioned their suggestion for the planning year 2010, depending if the value set for the year 2010 would be followed by subsequent decreases as review would warrant or if the selection would be set at some expected future calculation where the amount of wind capacity penetration would be higher (penetration is the topic of following question 3).

3) Do you see any pros or cons associated with starting with some higher capacity credit now (such as double digit percentage) as warranted from study information and decline to a lower number in future years, or fix capacity credit early on at some lower level that is expected to be appropriate as the penetration of wind resources increases.

   Response: Among the five that commented, two suggested starting lower because they were anticipating future more granular geographic data that would support increasing the credit. Therefore, they were being conservative on how to set the initial year. Those two entities seemed to reflect the notion of a "rules based" assignment of capacity. For example a rules based approach assigns capacity fairly to different locations by tracking performance at time of peak for example, but does not necessarily tie the value to loss of load expectation. A rules based approach is what MAPP and PJM currently use. The remaining three indicated to set the capacity credit at a higher level initially and deal with the consequences of higher penetration in the future (that may tend to drive the capacity credit downward).

4) If a practice of initially using a higher % credit at lower penetration levels and then later on decrease the % credit as penetration levels increase, were implemented; what are your comments about having that decline be consistent along the metric of some Design MW level as the driver? (Illustrated in Figures E4 and E6, and Table E3).

   Response: Four responded, with two recognizing that the amount of MW can be an important factor in deciding on a particular % capacity credit. One thought that setting some MW level as the criteria would be a poor or artificial construct, and the fourth restated the foundation of question #3 to start the % capacity credit higher in the initial year and change as warranted later on.

5) If the Design MW level (that attempts to combine the chance of wind resources showing up at peak with the increasing consequence as penetration increases) is adopted, what MW level do you feel is most appropriate? (see Figures E4 and E6, and Table E3).

   Response: Four responded, with two selecting the 1,000 MW level, one selecting the 600 MW level, and one indicating that a MW amount construct is inappropriate.

Item KIUC MISO 1-20) ***Refer to lines 10-12 of page 21 of your direct testimony. Please provide Documents and Studies, including workpapers, that obtain estimates of the Resource Adequacy benefits referred to as "Generator Availability Improvement." Isn't it true that, generally speaking, generator unit availability for the industry as a whole has improved over the past decade? How would one know, as a matter of causation, that the improvement in availability is attributable to unbundled reorganization of wholesale markets under MISO or attributed to other factors? Please elaborate.***

Response) The Midwest ISO is not in possession of data to determine if, or the extent to which, unit availability factors have been generally increasing. The Midwest ISO is in the process of conducting a study with outside vendor data to evaluate availability trends in other regions. The data for the Midwest ISO demonstrates increased availability of generation capacity within the Midwest ISO region. The underlying documents demonstrating the Generator Availability Improvement benefit as well as its causation can be found on the Midwest ISO web site in electronic format, as indicated in my testimony. Copies of those documents are attached.

Witness) **<u>Richard Doying</u>**