YUNKER & ASSOCIATES

Benjamin D. Allen
P.O. Box 21784
Lexington, KY 40522-1784

859-255-0629
FAX: 859-255-0746
ballen@desuetude.com

Drop Box
RECEIVED
OCT 26 2004
PUBLIC SERVICE COMMISSION

October 26, 2004
VIA HAND DELIVERY

Elizabeth O'Donnell, Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Dear Ms. O'Donnell:

Enclosed please find the original of the Responses to the Commission Staff's 10/13/04 Data Requests to be filed in the above-referenced proceeding on behalf of intervenor Midwest Independent Transmission System Operator, Inc.

Because this filing is voluminous and we are using the after-hours filing box, we will bring additional copies of these materials to the Commission tomorrow morning. Thank you for your attention to this matter.

Sincerely,

Ben Allen

Benjamin D. Allen

Enclosure

Drop Box
RECEIVED
OCT 2 6 2004
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Case No. 2003-00266

Responses of
Midwest Independent Transmission System Operator, Inc.
to the Commission Staff's 10/13/04 Data Requests

Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") hereby responds to the data requests propounded by the Commission Staff on October 13, 2004. Midwest ISO's response consists of one bound volume of text responses and attachments.

Respectfully submitted,

Katherine K. Yunker
Benjamin D. Allen
YUNKER & ASSOCIATES
P.O. Box 21784
Lexington, KY 40522-1784
(859) 255-0629
fax (859) 255-0746

Stephen G. Kozey
James C. Holsclaw
MIDWEST INDEPENDENT TRANSMISSION
SYSTEM OPERATOR, INC.
701 City Center Drive
Carmel IN 46032
(317) 249-5769
fax (859) 697-0792

Stephen L. Teichler
DUANE MORRIS, LLP
1667 K. Street N.W., Suite 700
Washington, DC 20006-1608
(202) 776-7830

By: ______________________

ATTORNEYS FOR THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

CERTIFICATE OF FILING AND SERVICE

I hereby certify that on this the 26th day of October, 2004, the original and ten (10) copies of the foregoing Responses to the Commission Staff's 10/13/04 Data Requests were hand-delivered to the Commission for filing, and a copy was sent, via ~~first-class U.S. mail~~ U.P.S., postage prepaid, to:

Michael S. Beer
Beth Cocanougher
LG&E ENERGY CORP.
220 West Main St.
P.O. Box 32030
Louisville, KY 40232-2030

David C. Boehm
BOEHM, KURTZ & LOWRY
Suite 2110 CBLD Building
36 East Seventh Street
Cincinnati, OH 45202

Elizabeth E. Blackford
Office of the Attorney General
UTILITY & RATE INTERVENTION DIVISION
1024 Capital Center Drive; Suite 200
Frankfort, KY 40601-8204

Kendrick R. Riggs
OGDEN, NEWELL & WELCH, PLLC
1700 Citizens Plaza
500 West Jefferson Street
Louisville, KY 40202

____

ATTORNEY FOR MIDWEST ISO

REQUEST:

1. What is the current calculation of the total exit fee if Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities ("KU") withdraw from MISO? Provide all details to support the calculation.

RESPONSE:

The exit fee for LGE/KU was calculated for three different years: 2005, 2007, and 2009. This was done to illustrate that the exit fee declines over time as the Midwest ISO's total obligations are paid off. The exit fee for each of these years is as follows:

2005: $40,239,034

2007: $27,162,976

2009: $14,553,128

The details underlying these figures are provided in the form of a spreadsheet showing the calculations themselves (attached as Exhibit 1 to this response), as well as the financial reports from which the exit fee spreadsheet input data were taken (attached as Exhibit 2).

Witness: Michael Holstein

LG&E/KU
Estimated Calculation of MISO Exit Obligation

	12/31/05			12/31/07			12/31/09		
	Schedule 10	Schedule 16	Schedule 17	Schedule 10	Schedule 16	Schedule 17	Schedule 10	Schedule 16	Schedule 17
Total Liabilities	$ 256,503,102	$ 71,830,717	$ 206,087,631	$ 258,717,232	$ 54,996,014	$ 153,289,212	$ 231,017,470	$ 33,391,009	$ 88,458,677
Less: Unamortized GridAm Costs	$ 23,898,183	$ -	$ -	$ 17,838,183	$ -	$ -	$ 11,778,183	$ -	$ -
Less: Unamortized ITC Costs	$ 672,682			$ 384,390			$ 240,244		
Less: Unamortized IP/Ameren Costs	$ 8,845,163			$ 6,831,741			$ 4,818,319		
Interest Expense	$ 65,111,690	$ 15,693,924	$ 30,896,837	$ 43,993,013	$ 9,357,834	$ 16,301,156	$ 23,215,983	$ 4,367,172	$ 7,600,798
Operating Leases	$ 14,385,359	$ 1,378,869	$ 8,395,399	$ 10,444,414	$ 1,075,346	$ 5,166,953	$ -	$ 745,549	$ 3,124,944
Total Obligations	$ 302,584,123	$ 88,903,510	$ 245,379,867	$ 288,100,345	$ 65,429,194	$ 174,757,321	$ 237,396,707	$ 38,503,731	$ 99,184,419
Less: Current Assets	$ 43,115,044	$ 19,569,949	$ 54,911,113	$ 70,950,496	$ 32,992,958	$ 91,532,004	$ 93,989,380	$ 31,454,696	$ 82,748,125
Net Obligation	$ 259,469,078	$ 69,333,561	$ 190,468,753	$ 217,149,849	$ 32,436,236	$ 83,225,317	$ 143,407,327	$ 7,049,034	$ 16,436,294
Billing Determinants									
Total Midwest ISO Projection	877,044,390	441,356,873	1,103,392,182						
Less: GridAm Projection	231,355,402	-	-						
Less: ITC	84,355,422								
Net Midwest ISO Projection	561,333,566	441,356,873	1,103,392,182						
LG&E-KU Projection	51,090,543	28,231,198	70,577,996						
LG&E-KU Portion of Total Billing Determinants	9.10%	6.40%	6.40%	9.10%	6.40%	6.40%	9.10%	6.40%	6.40%
Estimated Exit Obligation - By Schedule	$ 23,611,686	$ 4,437,348	$ 12,190,000	$ 19,760,636	$ 2,075,919	$ 5,326,420	$ 13,050,067	$ 451,138	$ 1,051,923
Total Estimated Exit Obligation (1)		**$40,239,034**			**$27,162,976**			**$14,553,128**	

Notes;
(1) Interest on senior unsecured notes over life of notes included as an obligation to be covered upon exiting the Midwest ISO
(2) Operating lease obligations for life of leases included as an obligation to be covered upon exiting the Midwest ISO.
(3) Load ratio share assumed to be the same for all years.
(4) Schedule 10 billing determinants are demand-based
(5) Total Liabilities and Current Assets based on 10-year financial projections prepared by Midwest ISO
(6) Interest Expense and Operating Leases computed per tabs in this spreadsheet.
(7) Unamortized GridAm. IP/Ameren. and ITC Costs based on financial statements of the Midwest ISO as of 12/31/03

Exit Fee Workpaper

Values from model V71a

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Total Current Assets	$ 95,470,415	$ 117,607,868	$ 161,139,623	$ 195,455,912	$ 207,199,004	$ 208,171,383	$ 206,098,176	$ 199,209,345	$ 77,186,231	$ 58,174,274
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Assets	$ 95.470.415	$ 117 607.868	$ 161.139.623	$ 195 455 912	$ 207.199.004	$ 208 171.383	$ 206.098 176	$ 199.209.345	$ 77 186.231	$ 58.174 274
Net Property & Equip										
Schedule 10	$ 95,718,731	$ 85,635,434	$ 69,253,724	$ 52,604,525	$ 37,208,866	$ 32,844,750	$ 31,656,182	$ 30,402,661	$ 29,171,045	$ 28,288,100
Schedule 16	$ 41,887,809	$ 38,870,436	$ 31,976,483	$ 24,457,592	$ 17,928,271	$ 10,991,731	$ 9,498,783	$ 9,235,719	$ 9,140,313	$ 8,803,438
Schedule 17	$ 114,593,443	$ 109,023,271	$ 90,172,034	$ 67,862,458	$ 48,884,625	$ 28,920,014	$ 23,225,504	$ 21,018,346	$ 20,590,938	$ 19,840,313
TOTAL	$ 252 199 983	$ 233.529.141	$ 191.402 242	$ 144,924.574	$ 104.021 761	$ 72.756.496	$ 64.380.469	$ 60.656.725	$ 58 902 295	$ 56.931.850
Allocation Factor (Total NP&E)										
Schedule 10	37 96%	36.66%	36 18%	38 30%	35 77%	45 15%	49 18%	50.12%	49 52%	49 70%
Schedule 16	16 61%	16 64%	16.71%	16 88%	17 24%	15.11%	14 75%	15.23%	15 52%	15 46%
Schedule 17	45.44%	46 69%	47 11%	46 83%	46 99%	39 75%	36.08%	34.65%	34.96%	34 85%
	100 01%	99 99%	100 00%	100.01%	100 00%	100.01%	100 01%	100 00%	100 00%	100 01%
Schedule 16 - LTD	$ 58,012,074	$ 73,012,074	$ 76,134,056	$ 70,970,323	$ 61,735,161	$ 48,500,000	$ 37,714,286	$ 25,500,000	$ 11,357,143	$ 2,678,571
Schedule 17 - LTD	$ 202,871,568	$ 197,871,568	$ 159,841,176	$ 134,560,784	$ 100,851,820	$ 71,142,857	$ 55,142,857	$ 40,571,428	$ 20,785,714	$ 12,499,999
LTD (Sch. 16 & 17)	$ 260.883.642	$ 270.883.642	$ 235.975.232	$ 205.531 107	$ 162.586 982	$ 119.642,857	$ 92.857 143	$ 66.071.428	$ 32.142.857	$ 15 178.571
Allocation of NP&E (Sch 16 & 17)										
Schedule 16	26.77%	26.28%	26.18%	26 49%	26.83%	27 54%	29 03%	30 53%	30 74%	30 73%
Schedule 17	73.23%	73.72%	73.82%	73 51%	73 17%	72.46%	70 97%	69.47%	69.26%	69 27%
	100 00%	100.00%	100.00%	100 00%	100 00%	100 00%	100 00%	100 00%	100.00%	100 00%
Allocation of LTD (Sch 16 & 17)										
Schedule 16	$ 69,838.551	$ 71.188.221	$ 61 778.316	$ 54.445 190	$ 43,622.087	$ 32.949.643	$ 26 956.428	$ 20 171.607	$ 9.880.714	$ 4 664.375
Schedule 17	$ 191.045.091	$ 199.695.421	$ 174.196.916	$ 151.085.917	$ 118 964 895	$ 86.693.214	$ 65.900.714	$ 45,899.821	$ 22 262.143	$ 10.514 196
Liabilities & Net Assets										
Schedule 10	$ 271,008,306	$ 256,503,102	$ 267,394,851	$ 258,717,232	$ 244,890,109	$ 231,017,470	$ 220,917,289	$ 210,748,220	$ 107,646,733	$ 87,498,708
Schedule 16	$ 82,236,678	$ 73,654,570	$ 76,732,746	$ 71,521,147	$ 62,233,681	$ 48,941,386	$ 38,093,199	$ 25,810,671	$ 11,593,245	$ 8,806,587
Schedule 17	$ 212,611,094	$ 204,263,778	$ 163,800,834	$ 136,764,079	$ 102,845,898	$ 72,906,320	$ 56,658,511	$ 41,814,113	$ 21,730,122	$ 19,648,812
Total Liabilities - Sch 16	$ 74,063.155	$ 71,830 717	$ 62.377.006	$ 54 996.014	$ 44 120.607	$ 33.391.009	$ 27 335.342	$ 20.482 278	$ 10 116.816	$ 10 792 391
Total Liabilities - Sch. 17	$ 200 785 517	$ 206.087,631	$ 178.156.574	$ 153 289.212	$ 120 958 972	$ 88 458.677	$ 67.416.368	$ 47 142.505	$ 23 206.550	$ 17.863,009
Unamortized GridAm	26,928,183	23,898,183	20,868,183	17,838,183	14,808,183	11,778,183	8,748,183	5,718,183	2,688,183	237,533
Unamortized Ameren Repayment - Int. Amortization	885,733	790,833	695,933	601,033	506,133	411,233	316,333	221,433	126,533	31,633
Unamortized Illinois Power Repayment - Int Amortization	247,555	222,380	197,205	172,030	146,855	121,680	96,505	71,329	46,154	20,979
Unamortized Illinois Power - Regulatory Asset	8,718,585	7,831,950	6,945,314	6,058,678	5,172,042	4,285,406	3,398,771	2,512,135	1,625,499	738,863
Total	9.851.874	8 845.163	7,838.452	6.831.741	5.825.030	4.818.319	3,811,608	2 804.898	1 798 187	791 476

PRESENT VALUE - LEASES AND INTEREST AT 12/31/04 **SCHEDULE 10**

INTEREST ON CAPITAL LEASES 1%	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	910,878.49	817,183.42	701,473.65	619,902.14	558,223.29	500,629.17	437,486.17	368,598.41	293,324.00	211,070.83
NPV (begin '04)	$4,330,893.61	$3,557,019.12	$2,891,115.66	$2,300,124.68	$1,764,902.64	$1,282,022.50				

OPERATING LEASES	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	1,872,438.73	2,721,502.88	2,423,230.76	1,782,627.53	1,772,026.37	1,704,081.88	1,755,204.34	1,807,860.47	1,862,096.28	1,917,959.17
NPV (end of year)	$16,937,486.61	$14,385,358.60	$12,105,981.43	$10,444,413.72	$8,776,831.49	$7,160,517.92				

DEBT INTEREST	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	11,029,761.13	10,371,100.52	10,182,085.43	10,815,123.80	10,435,906.70	10,056,689.60	9,712,142.85	9,471,607.14	2,989,285.70	136,971.72
NPV (end of year)	$71,213,635.14	$61,554,670.97	$51,988,131.25	$41,692,888.76	$31,673,910.95	$21,933,960.46				
GRAND TOTAL NPV	$92,482,015.36	$79,497,048.69	$66,985,228.34	$54,437,427.17	$42,215,645.07	$30,376,500.87				

PRESENT VALUE - LEASES AND INTEREST AT 12/31/04 SCHEDULE 16

INTEREST ON CAPITAL LEASES	2004	1% 2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	106,935.93	71,776.17	55,417.63	51,356.39	46,918.64	42,069.45	36,770.69	30,980.68	24,653.87	17,740.50
NPV (end of year)	$362,876.91	$294,729.50	$242,259.16	$193,325.36	$148,339.98	$107,753.93				

OPERATING LEASES	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	153,051.00	157,642.53	162,371.81	167,242.96	172,260.25	177,428.06	182,750.90	188,233.42	193,880.43	199,696.84
NPV (end of year)	$1,521,298.37	$1,378,868.82	$1,230,285.70	$1,075,345.60	$913,838.81	$745,549.14				

DEBT INTEREST	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
STD Interest	49,902.85	100,465.15	-	-	-	-	-	-	-	292,872.37
LTD Interest	2,225,398.55	2,839,585.87	3,344,772.17	3,165,990.29	2,761,258.10	2,300,425.92	1,704,092.85	1,183,607.13	1,027,126.18	138,972.02
TOTAL	2,275,301.40	2,940,051.03	3,344,772.17	3,165,990.29	2,761,258.10	2,300,425.92	1.704.092 85	1.183.607 13	1.027.126 18	431.844 38
NPV (end of year)	$18,157,669.24	$15,399,194.91	$12,208,414.68	$9,164,508.54	$6,494,895.52	$4,259,418.56				

GRAND TOTAL NPV	$20,041,844.51	$17,072,793.23	$13,680,959.55	$10,433,179.50	$7,557,074.31	$5,112,721.63

Exhibit 1 to Q #1

PRESENT VALUE - LEASES AND INTEREST AT 12/31/04 SCHEDULE 17

INTEREST ON CAPITAL LEASES 1%	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	440,883.07	497,410.65	353,327.49	233,187.32	187,674.50	168,277.75	147,082.71	123,922.66	98,615.43	70,961.93
NPV (end of year)	$1,815,739.14	$1,336,485.88	$996,523.25	$773,301.16	$593,359.68	$431,015.53				

OPERATING LEASES	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL	974,646.51	1,660,167.16	1,679,988.45	1,700,406.73	1,388,298.02	743,683.69	765,994.20	788,974.03	812,643.25	837,022.55
NPV (end of year)	$9,956,006.56	$8,395,399.46	$6,799,365.00	$5,166,952.92	$3,830,324.43	$3,124,943.98				

DEBT INTEREST	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
STD Interest	95,949.56	8,061.29	-	-	-	-	-	-	-	345,796.28
LTD Interest	6,527,826.32	8,659,813.60	8,163,141.40	6,381,885.91	4,982,049.47	3,638,313.04	2,575,907.13	1,875,142.85	1,947,992.85	580,841.94
TOTAL	6,623,775.87	8,667,874.89	8,163,141.40	6,381,885.91	4,982,049.47	3,638,313.04	2,575,907 13	1.875.142 85	1.947.992 85	926.638.22
NPV (end of year)	$37,849,728.40	$29,560,350.80	$21,692,812.91	$15,527,855.13	$10,701,084.20	$7,169,782.01				

GRAND TOTAL NPV	$49,621,474.11	$39,292,236.14	$29,488,701.17	$21,468,109.21	$15,124,768.31	$10,725,741.52

Midwest ISO Financial Projections
Annual Income Statement
($ in thousands, except Billing Rates)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Revenue										
ISO Cost Recovery Adder	113,467	125,423	128,891	132,409	133,208	123,292	122,610	125,339	122,724	116,114
FTR Cost Recovery Adder	-	26,110	32,484	33,307	32,385	32,842	27,391	26,286	23,907	23,417
Energy Market Cost Recovery Adder	-	87,534	105,620	106,502	103,088	103,797	90,190	87,774	77,562	76,318
FERC Assessment	31,031	18,000	19,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Contract Revenue (MAPPCOR, SPP, AEP, Engr. Studies)	8,025	8,266	8,514	8,769	3,093	3,186	3,281	3,380	3,481	3,586
Interest on Cash Balance	951	636	1,394	1,907	2,175	2,272	2,201	2,110	1,171	178
Miscellaneous Revenue	124	128	132	135	140	144	148	153	157	162
TOTAL REVENUE	153,598	266,096	296,035	303,030	294,089	285,533	265,821	265,041	249,003	239,774
Operating Expenses										
Salaries and Benefits	55,174	74,352	77,819	80,806	78,438	80,955	83,547	86,218	88,968	91,801
Outside Services	44,188	35,180	36,370	37,461	38,585	39,742	40,934	42,163	43,427	44,730
Occupancy and Telecom	12,857	15,448	15,502	15,224	15,253	14,903	15,350	15,811	16,285	16,774
Supplies, Travel and Computer Maintenance	13,996	24,916	27,330	28,150	28,995	29,865	30,761	31,683	32,634	33,613
FERC Assessment	17,089	18,000	19,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Other	5,442	6,202	6,388	6,580	6,777	6,980	7,190	7,405	7,628	7,856
TOTAL OPERATING EXPENSES	148,746	174,099	182,409	188,220	188,047	192,445	197,783	203,280	208,942	214,774
EBITDA	4,853	91,997	113,625	114,810	106,042	93,087	68,038	61,761	40,061	24,999
Interest Expenses										
Interest on Long Term Debt	19,783	21,871	21,690	20,363	18,179	15,995	13,992	12,530	5,964	857
Interest on Short Term Debt	146	109	-	-	-	-	-	-	-	639
Interest on Capital Leases	1,459	1,386	1,110	904	793	711	621	524	417	300
TOTAL INTEREST EXPENSES	21,388	23,365	22,800	21,267	18,972	16,706	14,613	13,054	6,381	1,795
Depreciation and Amortization										
Depreciation on Capital Assets	21,933	53,730	62,927	64,778	59,203	49,565	26,676	22,024	20,054	19,370
Amort. Capitalized ISO Start-Up Costs	9,695	9,819	9,819	9,819	1,263	-	-	-	-	-
Amort. Capitalized FTR Start-Up Costs	-	2,691	3,230	3,230	3,230	3,230	3,230	3,230	538	-
Amort. Capitalized Energy Market Start-Up Costs	-	8,379	10,054	10,054	10,054	10,054	10,054	10,054	1,676	-
Amort. GridAm Regulatory Assets	2,856	3,125	3,125	3,125	3,125	3,125	3,125	3,125	3,125	2,546
Amort. Post_Transition Regulatory Assets	-	-	-	-	1,573	1,716	1,716	1,716	1,716	143
Amort. Illinois Power Regulatory Asset	152	912	912	912	912	912	912	912	912	912
Amort. Deferred ISO Revenue - $25 Million Settlement	-	-	-	-	5,000	5,000	5,000	5,000	5,000	-
Amort. Reimbursable Market Participant Costs	-	1,988	2,386	2,386	2,386	2,386	2,386	2,386	398	-
Amort. of Deferred Revenue - Market Implementation	-	-	-	-	-	-	-	-	-	-
Amort. Capitalized Bond Offering Costs	419	504	504	504	444	393	326	261	261	233
TOTAL DEPRECIATION AND AMORTIZATION	35,055	81,147	92,956	94,807	87,189	76,381	53,425	48,707	33,680	23,204
Increase Deferred Asset										
Deferred Expense - FERC Fee	(13,942)	-	-	-	-	-	-	-	-	-
Deferred ISO Revenue - Due to Rate Cap or Settlement	3,811	1,255	2,131	1,265	120	-	-	-	-	-
FTR Start-Up Costs	14,863	2,944	-	-	-	-	-	-	-	-
Energy Market Start-Up Costs	46,857	8,316	-	-	-	-	-	-	-	-
Billing Determinants										
ISO Cost Recovery Adder MWhs - Demand Based (000)	797,998	877,044	894,585	912,477	930,727	949,341	968,328	987,694	1,007,448	1,027,597
ISO Cost Recovery Adder MWhs - Energy (000)	607,214	662,756	676,011	689,531	703,321	717,388	731,736	746,370	761,298	776,524
Unbundled (TRANSLInk) ISO CRA MWhs (000)	-	-	-	-	-	-	-	-	-	-
FTR Cost Recovery Adder - FTR MW Volume (000)	-	441,357	540,809	551,625	562,657	573,910	585,389	597,096	609,038	621,219
Energy Market CRA - MWh (Load plus Generation) (000)	-	1,103,392	1,352,021	1,379,062	1,406,643	1,434,776	1,463,471	1,492,741	1,522,596	1,553,047
Billing Rates										
Schedule 10 - Demand Based- $ per MWh	0.1127	0.1126	0.1126	0.1126	0.1111	0.1005	0.0980	0.0983	0.0943	0.0873
Schedule 10 - Energy- $ per MWh	0.0370	0.0372	0.0372	0.0372	0.0367	0.0333	0.0324	0.0325	0.0312	0.0289
Schedule 10 - Total- $ per MWh	0.1498	0.1498	0.1498	0.1498	0.1478	0.1338	0.1304	0.1308	0.1255	0.1162
Portion of Sch 10 - Demand Based	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Portion of Sch 10 - Energy	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Schedule 16 - $ per FTR MW Volume	-	0.0592	0.0601	0.0604	0.0576	0.0572	0.0468	0.0440	0.0393	0.0377
Schedule 17 - $ per MWh (Load plus Generation)	-	0.0793	0.0781	0.0772	0.0733	0.0723	0.0616	0.0588	0.0509	0.0491

Midwest ISO Financial Model
Annual Cash Flow Statement
($ 000)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Operating Activities										
Net Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation	$ 21,933	$ 53,730	$ 62,927	$ 64,778	$ 59,203	$ 49,565	$ 26,676	$ 22,024	$ 20,054	$ 19,370
Amort. Capitalized Pre-Operating Expenses	$ 9,695	$ 20,889	$ 23,103	$ 23,103	$ 14,547	$ 13,284	$ 13,284	$ 13,284	$ 2,214	$ -
Amort. GridAm Regulatory Assets	$ (5,219)	$ 3,125	$ 3,125	$ 3,125	$ 3,125	$ 3,125	$ 3,125	$ 3,125	$ 3,125	$ 2,546
Amort. Post_Transition Regulatory Assets	$ -	$ -	$ -	$ -	$ 1,573	$ 1,716	$ 1,716	$ 1,716	$ 1,716	$ 143
Amort. Illinois Power Regulatory Assets	$ (8,966)	$ 912	$ 912	$ 912	$ 912	$ 912	$ 912	$ 912	$ 912	$ 912
Amort. Reimbursable Market Participant Costs	$ (14,976)	$ 1,988	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 2,386	$ 398	$ -
Amort. Capitalized Bond Offering Costs	$ 409	$ 440	$ 440	$ 440	$ 381	$ 340	$ 326	$ 261	$ 261	$ 233
Amort. Deferred ISO Revenue - $25 Million Settlement	$ -	$ -	$ -	$ -	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ -
Amort. of Deferred Revenue - Market Implementation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(Increase) Decrease Deferred Regulatory Asset	$ (51,590)	$ (12,515)	$ (2,131)	$ (1,265)	$ (120)	$ 0	$ 0	$ 0	$ 0	$ 0
(Increase) Decrease in Other Current Assets	$ (5,446)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Increase (Decrease) in Operating Liabilities	$ (8,369)	$ 228	$ 250	$ 250	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
TOTAL OPERATING ACTIVITIES	$ (62,530)	$ 68,796	$ 91,012	$ 93,729	$ 87,006	$ 76,328	$ 53,425	$ 48,707	$ 33,680	$ 23,204
Investing Activities										
Capital Expenditures - Transmission Services	$ (17,754)	$ (12,611)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)
Capital Expenditures - FTR Services	$ (15,673)	$ (4,990)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,300)	$ (3,025)
Capital Expenditures - Energy Market Services	$ (58,395)	$ (17,458)	$ (10,000)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (7,500)	$ (6,875)
TOTAL CAPITAL EXPENDITURES	$ (91,822)	$ (35,059)	$ (20,800)	$ (18,300)	$ (18,300)	$ (18,300)	$ (18,300)	$ (18,300)	$ (18,300)	$ (17,400)
Financing Activities										
Change in Capital Lease Obligation	$ 4,145	$ (6,630)	$ (3,743)	$ (2,890)	$ (884)	$ (966)	$ (1,055)	$ (1,153)	$ (1,260)	$ (1,377)
Settlement Offset - Member Withdrawal	$ (25,500)	$ (2,000)	$ (3,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)	$ (4,000)
Change in Long Term Debt	$ 202,331	$ -	$ (20,000)	$ (34,286)	$ (52,143)	$ (52,143)	$ (32,143)	$ (32,143)	$ (132,143)	$ (32,143)
TOTAL FINANCING ACTIVITIES	$ 180,976	$ (8,630)	$ (26,743)	$ (41,176)	$ (57,027)	$ (57,109)	$ (37,198)	$ (37,296)	$ (137,403)	$ (37,520)
Cash at Start of Year	$ 16,107	$ 42,559	$ 64,697	$ 108,229	$ 142,545	$ 154,288	$ 155,260	$ 153,187	$ 146,298	$ 24,275
Change in Cash	$ 26,635	$ 25,170	$ 43,532	$ 34,316	$ 11,743	$ 972	$ (2,073)	$ (6,889)	$ (122,023)	$ (31,716)
Short Term Debt Issued (Redeemed)	$ (183)	$ (3,033)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,704
Cash at End of Year	$ 42,559	$ 64,697	$ 108,229	$ 142,545	$ 154,288	$ 155,260	$ 153,187	$ 146,298	$ 24,275	$ 5,263

Midwest ISO Financial Model
Annual Balance Sheet
($ 000)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
ASSETS											
Current Assets											
Cash and Cash Equivalents	$ 16,107	$ 42,559	$ 64,697	$ 108,229	$ 142,545	$ 154,288	$ 155,260	$ 153,187	$ 146,298	$ 24,275	$ 5,263
Other Current Assets	$ 47,465	$ 52,911	$ 52,911	$ 52,911	$ 52,911	$ 52,911	$ 52,911	$ 52,911	$ 52,911	$ 52,911	$ 52,911
TOTAL CURRENT ASSETS	$ 63,572	$ 95,470	$ 117,608	$ 161,140	$ 195,456	$ 207,199	$ 208,171	$ 206,098	$ 199,209	$ 77,186	$ 58,174
Property and Equipment											
Net Property and Equipment - Transmission Service	$ 97,882	$ 95,719	$ 85,635	$ 69,254	$ 52,605	$ 37,209	$ 32,845	$ 31,656	$ 30,403	$ 29,171	$ 28,288
Net Property and Equipment - FTR Services	$ 26,635	$ 41,888	$ 38,870	$ 31,976	$ 24,458	$ 17,928	$ 10,992	$ 9,499	$ 9,236	$ 9,140	$ 8,803
Net Property and Equipment - Energy Market Services	$ 57,794	$ 114,593	$ 109,023	$ 90,172	$ 67,862	$ 48,885	$ 28,920	$ 23,226	$ 21,018	$ 20,591	$ 19,840
TOTAL NET PROPERTY AND EQUIPMENT	$ 182,312	$ 252,200	$ 233,529	$ 191,402	$ 144,925	$ 104,022	$ 72,756	$ 64,380	$ 60,657	$ 58,902	$ 56,932
Other Assets											
Net Capitalized Pre-Operating Costs - Transmission Service	$ 40,414	$ 30,720	$ 20,901	$ 11,082	$ 1,263	$ -	$ -	$ -	$ -	$ -	$ -
Net Capitalized Pre-Operating Costs - FTR Services	$ 4,799	$ 19,663	$ 19,915	$ 16,686	$ 13,456	$ 10,227	$ 6,997	$ 3,768	$ 538	$ -	$ -
Net Capitalized Pre-Operating Costs - Energy Market Services	$ 15,208	$ 62,065	$ 62,002	$ 51,948	$ 41,893	$ 31,839	$ 21,785	$ 11,730	$ 1,676	$ -	$ -
Net Reimbursable Market Participant Costs	$ 1,724	$ 16,700	$ 14,712	$ 12,326	$ 9,940	$ 7,555	$ 5,169	$ 2,783	$ 398	$ -	$ -
Net Capitalized Bond Offering Costs	$ 1,199	$ 3,448	$ 2,944	$ 2,441	$ 1,937	$ 1,493	$ 1,100	$ 774	$ 513	$ 252	$ 19
Net Deferred Revenue - ISO CRA Settlement	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 20,000	$ 15,000	$ 10,000	$ 5,000	$ -	$ -
Net Capitalized GridAm Regulatory Asset	$ 22,595	$ 27,814	$ 24,689	$ 21,564	$ 18,439	$ 15,314	$ 12,189	$ 9,065	$ 5,940	$ 2,815	$ 269
Net Post_Transition Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ 7,008	$ 5,292	$ 3,576	$ 1,859	$ 143	$ -
Net Capitalized Illinois Power Regulatory Asset	$ -	$ 8,966	$ 8,054	$ 7,143	$ 6,231	$ 5,319	$ 4,407	$ 3,495	$ 2,583	$ 1,672	$ 760
Net Deferred Revenue - Market Implementation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Expense - FERC Fee Assessment	$ 13,942	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Deferred Revenue - Due to Rate Cap	$ -	$ 3,811	$ 5,066	$ 7,197	$ 8,462	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OTHER ASSETS	$ 124,881	$ 198,187	$ 183,284	$ 155,386	$ 126,622	$ 98,755	$ 71,939	$ 45,190	$ 18,507	$ 4,882	$ 1,048
TOTAL ASSETS	$ 370,764	$ 545,857	$ 534,421	$ 507,928	$ 467,002	$ 409,976	$ 352,867	$ 315,669	$ 278,373	$ 140,970	$ 116,154
LIABILITIES AND NET ASSETS											
Liabilities											
Current Liabilities	$ 69,654	$ 75,100	$ 75,100	$ 75,100	$ 75,100	$ 75,100	$ 75,100	$ 75,100	$ 75,100	$ 75,100	$ 75,100
FERC Assessment Liability	$ 18,088	$ 4,272	$ 4,500	$ 4,750	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Accrued Liabilities	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749	$ 1,749
Capitalized Leases	$ 18,426	$ 22,571	$ 15,941	$ 12,198	$ 9,308	$ 8,424	$ 7,458	$ 6,403	$ 5,250	$ 3,990	$ 2,613
Short Term Debt	$ 3,216	$ 3,033	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,704
Long Term Debt	$ 200,000	$ 405,000	$ 405,000	$ 385,000	$ 350,714	$ 298,571	$ 246,429	$ 214,286	$ 182,143	$ 50,000	$ 17,857
Settlement Proceeds - Member Withdrawal	$ 59,631	$ 34,131	$ 32,131	$ 29,131	$ 25,131	$ 21,131	$ 17,131	$ 13,131	$ 9,131	$ 5,131	$ 1,131
TOTAL LIABILITIES	$ 370,764	$ 545,857	$ 534,421	$ 507,928	$ 467,002	$ 409,976	$ 352,867	$ 315,669	$ 278,373	$ 140,970	$ 116,154
Net Assets											
Retained Earnings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL NET ASSETS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL LIABILITIES AND NET ASSETS	$ 370,764	$ 545,857	$ 534,421	$ 507,928	$ 467,002	$ 409,976	$ 352,867	$ 315,669	$ 278,373	$ 140,970	$ 116,154

REQUEST:

2. Has the current amount of the exit fee changed from MISO's previous calculation filed in this case? If yes, explain why the amount has changed.

RESPONSE:

Yes, the projected exit fee has changed. The exit fee is a pro rata share of "...all financial obligations incurred and payments applicable to time periods prior to the effective date of the withdrawal..." per the terms of the Transmission Owners Agreement. The projected financial obligations of the Midwest ISO have increased relative to the previous forecast provided in this case. This increase is attributable to: (1) the FERC-ordered change in the start date for the FTR and energy markets, which delayed the start of revenue recovery for market costs thus increasing the accumulated pre-operating expenses for market services, and (2) an increase in the project-related costs to implement the FTR and energy markets.

In June of 2004, the Board of Directors authorized modifications to the budget for the project. These changes were made to incorporate: (1) additional IT infrastructure, including design and implementation efforts, (2) enhanced functionality and testing of the systems that will drive the FTR and energy market services, (3) additional IT and operations staffing, and (4) additional pre-operational expenses due to the revised commencement date of March 1, 2005.

The net effect of these board-authorized changes to the project was to increase the total project cost from $191.9 million to $247.8 million through March 1, 2005, the revised start date for the FTR and energy market services.

Witness: Michael Holstein

The revised project costs by category are as follows:

Capital Expenditures as of 2/28/05	$ 157.1 million
Pre-Operating Expenses as of 2/28/05	90.7 million
Total Cost for 3/1/05 start date	$ 247.8 million

The projected financials used to compute the exit fee are based on the revised start date of March 1, 2005, and the revised cost of $247.8 million to complete and implement the FTR and energy market services.

REQUEST:

3. Is there a plan at MISO to consolidate control areas and reduce individual control area responsibilities? If yes, explain the plan and the anticipated timing of its implementation.

RESPONSE:

No. The Midwest ISO has been directed by the FERC in the August 6, 2004, EMT Order (108 FERC ¶ 61,163 (2004)) to discuss with stakeholders the feasibility of Control Area consolidation.

Witness: Ronald R. McNamara

REQUEST:

4. If control areas are consolidated at MISO, and functions are reassigned to a central control area, would LG&E and KU be able to continue operating their own control area and dispatching power within their own footprint as they do now?

RESPONSE:

As stated in the response to Request No. 3, the Midwest ISO does not have any plans currently to consolidate Control Areas. It would be premature at this point to speculate about this issue.

Witness: Ronald R. McNamara

REQUEST:

5. Explain the overall benefits to the MISO footprint of consolidating existing control areas.

RESPONSE:

See response to Request Nos. 3 and 4.

Witness: Ronald R. McNamara

REQUEST:

6. Explain whether there are any potential negative impacts to utilities within MISO, such as LG&E and KU, of consolidating control areas within the MISO footprint.

RESPONSE:

See response to Request Nos. 3 and 4.

Witness: Ronald R. McNamara

REQUEST:

7. Refer to Dr. McNamara's testimony at page 3.

   a. Are any of the LG&E or KU grandfathered transmission service agreements (GFA's) affected by the September 16, 2004 Order of the Federal Energy Regulatory Commission?

   b. If so, which GFA's are affected, how many megawatts are involved, and what impact, if any, will they have on Schedule 16 and 17 charges?

RESPONSE:

   a. Yes.

   b. See Appendix B to FERC's Order issued on September 16, 2004 regarding GFAs. GFA numbers 214, 215, 216, 219, 220, 221, 222, 224, 225, and 229 are affected by the Order. The megawatts are reported in Appendix B as well. Appendix B to the FERC's Order is attached to this response as Exhibit 1. Regarding Schedules 16 and 17 charges, please see Ordering Paragraph 6 of the September 16 Order, attached to this response as Exhibit 2.

Witness: Ronald R. McNamara

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
2	Carve Out	0.80		Alliant Energy - IPL	N/A	N/A
3	Carve Out	7.00		Alliant Energy - IPL	N/A	N/A
4	Carve Out	1.50		Alliant Energy - IPL	N/A	N/A
5	Carve Out	0.50		Alliant Energy - IPL	N/A	N/A
6	Carve Out	3.00		Alliant Energy - IPL	N/A	N/A
7	Carve Out	0.60		Alliant Energy - IPL	N/A	N/A
8	Carve Out	0.75		Alliant Energy - IPL	N/A	N/A
9	Carve Out	0.15		Alliant Energy - IPL	N/A	N/A
11	Carve Out	3.20		Alliant Energy - IPL	N/A	N/A
12	Carve Out	144.00	We note that Great River and Alliant report that they have entered into a letter of intent to terminate contract by 3/1/05.	Alliant Energy - IPL	N/A	N/A
14	Carve Out	12.90	Maximum MW is total of largest historical capacity for each source-sink pair	Alliant Energy - IPL	N/A	N/A
16	Carve Out	591.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
17	Carve Out	24.07		Alliant Energy - IPL	N/A	N/A
19	Carve Out	37.00		Alliant Energy - IPL	N/A	N/A
20	Carve Out	0.00	GFA Nos. 20 & 41 are two separate contracts that establish one service; Maximum Cumulative MW for both reported in GFA No. 41	Alliant Energy - IPL	N/A	N/A
28	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
29	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
30	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
31	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
34	Option B	97.53		Alliant Energy - IPL	Southern Minnesota Muni Pwr Agency	Southern Minnesota Muni Pwr Agency
35	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
36	Carve Out	0.00	Maximum Cumulative MW for GFA Nos. 16, 28, 29, 30, 31, 32, 33, 35 and 36 reported in GFA No. 16	Alliant Energy - IPL	N/A	N/A
39	Carve Out	5.00		Alliant Energy - IPL	N/A	N/A
41	Carve Out	44.20	GFA Nos. 20 & 41 are two separate contracts that establish one service; Maximum Cumulative MW for both reported in GFA No. 41	Alliant Energy - IPL	N/A	N/A
94	Option A	75.40		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
95	Option A	3.00		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
96	Option A	4.90	Maximum MW is largest capacity of the historical data provided	American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
97	Option A	0.90		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
98	Option A	4.60		American Tx Co. - WPL	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
100	Option A	43.00		American Tx Co. - Edison Sault	Wisconsin Electric Pwr Co	Wisconsin Electric Pwr Co
101	Carve Out	5.20		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
102	Carve Out	4.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
103	Carve Out	7.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
104	Carve Out	4.50		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
105	Carve Out	4.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
106	Carve Out	5.40		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
107	Carve Out	5.60		American Tx Co. - Upper Peninsula Pwr	N/A	N/A
108	J & R	0.50		American Tx Co. - WPS	Wisconsin Public Service Corp	Wisconsin Public Service Corp
109	J & R	1.40		American Tx Co. - WPS	Wisconsin Public Service Corp	Wisconsin Public Service Corp
110	J & R	0.70		American Tx Co. - WPS	Wisconsin Public Service Corp	Wisconsin Public Service Corp
111	Carve Out	70.00		American Tx Co. - WPS	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
112	Carve Out	20.90		American Tx Co. - WPS	N/A	N/A
141	Option B	72.00	GFA Nos. 141, 182, and 342 are all the same contract; Maximum MW for GFA No. 141 covers power transmitted from PSI to Hoosier	Cinergy - PSI		
142	Option A/B	0.00	GFA Nos. 142 and 144 are related; Maximum Cumulative MW for GFA Nos. 142 and 144 are reported under GFA No. 144.	Cinergy - PSI	Cinergy Services	Cinergy Services
144	Option A/B	396.00	GFA Nos. 144, 188 and 347 are all same the contract; GFA No. 144 Maximum MW covers service to Wabash and also includes service under GFA No. 142.	Cinergy - PSI	Wabash Valley Pwr Association	Wabash Valley Pwr Association
145	J & R	64.00		Cinergy - PSI	PSI	PSI
146	J & R	130.00		Cinergy - PSI	PSI	PSI
147	J & R	38.00		Cinergy - PSI	PSI	PSI
152	Option B	203.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	Cinergy - Cincinnati G&E	Cincinnati Gas & Electric Co	Cinergy Services
159	Option B	60.00		Cinergy - Union Light, Heat & Pwr	Cincinnati Gas & Electric Co	East Kentucky Pwr Coop
161	Carve Out	1101.00	Maximum MW covers GFA Nos. 161 - 177	Hoosier	N/A	N/A
162	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
163	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
164	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
165	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
166	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
167	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
168	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
169	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
170	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
171	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
172	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
173	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
174	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
175	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
176	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A
177	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 161.	Hoosier	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
178	Carve Out	2.00		Hoosier	N/A	N/A
179	Carve Out	400.00		Hoosier	N/A	N/A
182	Option B	7.00	GFA Nos. 141, 182, and 342 are all the same contract; GFA No. 182 Maximum MW covers power transmitted from SIGECO to Hoosier.	Hoosier	Hoosier	Hoosier
183	Carve Out	0.00	Hoosier & SIGECO indicate PSI provides service that it reports in another GFA.	Hoosier	N/A	N/A
185	Carve Out	232.00	Maximum MW is largest capacity listed in the historical data provided	Hoosier	N/A	N/A
186	Carve Out	40.00		Hoosier	N/A	N/A
188	Option A	595.52	GFA Nos. 144, 188 and 347 are all the same contract; GFA No. 188 maximum MW covers service to IMPA	Indiana Municipal Power Agency	Cinergy Services	Cinergy Services
189	Carve Out	0.00	Service provided under GFA No. 189 reported in GFA No. 188 maximum MW	Indiana Municipal Power Agency	N/A	N/A
190	Carve Out	0.00	Service provided under GFA No. 190 reported in the maximum cumulative MW for GFA No. 188	Indiana Municipal Power Agency	N/A	N/A
192	J & R	0.00	GFA Nos. 192 and 214 are the same contract	Indiana Municipal Power Agency	Indiana Muni Pwr Agency	LG&E
200	Carve Out	13.00		Indianapolis Power & Light	N/A	N/A
205	Carve Out	1872.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	International Transmission Co	N/A	N/A
206	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	International Transmission Co	N/A	N/A
207	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	International Transmission Co	N/A	N/A
209	Carve Out	234.49	MW listed for GFA No. 209 covers service under GFA No. 210	International Transmission Co	N/A	N/A
210	Carve Out	0.00	MW listed for GFA No. 209 covers service under GFA No. 210	International Transmission Co	N/A	N/A
211	Carve Out	5.90		International Transmission Co	N/A	N/A
212	Carve Out	37.13	Maximum MW is largest capacity listed in historical data presented for interchange service	International Transmission Co	N/A	N/A
213	Carve Out	85.00	We note that submittal indicated that service under this GFA is part of Detroit Edison's network load and conversion will be addressed in same manner as all other network load.	International Transmission Co	N/A	N/A
214	Option B	66.00		LG&E Energy - LG&E	Indiana Muni Pwr Agency	LG&E

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
215	J & R	113.00		LG&E Energy - LG&E	LG&E	LG&E
216	Convert to TEMT	158.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract.	LG&E Energy - LG&E	N/A	N/A
219	J & R	0.00	Parties state that no firm transmission currently taken under contract	LG&E Energy - KU	TVA	TVA
220	Carve Out	414.00	Maximum MW is largest capacity listed in historical data. MW listed are baseload and should be carved out.	LG&E Energy - KU	N/A	N/A
221	J & R	143.00	Maximum MW is largest capacity listed in historical data provided	LG&E Energy - KU	LG&E	LG&E
222	Carve Out	1014.00	GFA Nos. 222 and 406 are the same contract; GFA No. 448 is a companion; Maximum Cumulative MW for all three is listed in GFA No. 222.	LG&E Energy - KU	N/A	N/A
223	Option A	333.00	Maximum MW does not include service from customer because customer is not a Midwest ISO transmission owner.	LG&E Energy - KU	LG&E	LG&E
224	Convert to TEMT	56.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	LG&E Energy - KU	N/A	N/A
225	J & R	72.00		LG&E Energy - KU	TVA	TVA
254	Carve Out	15.50		METC	N/A	N/A
255	Carve Out	105.00		METC	N/A	N/A
256	Carve Out	39.36	Related to GFA No. 422; Maximum Cumulative MW reported in GFA No. 256	METC	N/A	N/A
257	Carve Out	232.14	Related to GFA No. 421; Maximum Cumulative MW reported in GFA No. 257	METC	N/A	N/A
266	Carve Out	90.00		METC	N/A	N/A
267	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	METC	N/A	N/A
268	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	METC	N/A	N/A
269	Carve Out	0.00	MW listed for GFA No 205 covers GFA Nos. 205-207 and 267-269	METC	N/A	N/A
273	Carve Out until hearing resolved	182.70	GFA Nos. 273 and 311 are the same contract. maximum MW reported was 710, but that is MPC's total load. Subtracted value of GFA Nos. 309 and 317. 136.7 MW = share of Coyote plant; Service to NWPS = 46 MW;	Montana-Dakota Utilities	N/A	N/A
274	Carve Out	115.70	GFA Nos. 274 and 320 are the same contract; maximum MW is NWPS load only; OTP and MDU report load as network load under the Midwest ISO OATT;	Montana-Dakota Utilities	N/A	N/A
284	Carve Out until hearing resolved	220.00	GFA Nos. 285 and 425 are related; maximum MW reported in GFA No. 284	Minnesota Power	N/A	N/A
285	Option B	108.00		Minnesota Power	Wisconsin Public Pwr Inc	Wisconsin Public Pwr Inc
286	Carve Out	43.00		Minnesota Power	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
289	Carve Out	16.00	Maximum MW includes two services reported - 12 MW and 4 MW	Minnesota Power	N/A	N/A
291	Carve Out	85.00	Maximum MW for SWL+P loads are aggregated with several other municipalities and are reported GFA No. 291. Maximum MW represents highest of range for the sink Mp.muni.swlp	Minnesota Power	N/A	N/A
293	Carve Out	2.66	Service provided by DPC to NWEC does not use Midwest ISO facilities, so not included in maximum MW	Northwestern Wisconsin Elec	N/A	N/A
297	Carve Out until hearing	150.00		Otter Tail Power Company	N/A	N/A
300	J & R	1.16	reported as 1,160 KW	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Power
302	J & R	0.23	reported as 230 KW	Otter Tail Power Company	Otter Tail Power	Otter Tail Power
304	J & R	0.57		Otter Tail Power Company	Otter Tail Power	Otter Tail Power
306	Carve Out until hearing resolved	152.00	Maximum MW includes only GRE's load of 152 MWs because OTP load of 110 MWs already included in OTP network load under Midwest ISO OATT	Otter Tail Power Company	N/A	N/A
308	Carve Out	16.20		Otter Tail Power Company	N/A	N/A
309	Carve Out until hearing resolved	331.90	Maximum MW reported was 710, but that is MPC's total load. Subtracted value of GFA Nos. 273 and 317.	Otter Tail Power Company	N/A	N/A
311	Carve Out until hearing resolved	0.00	GFA No. 273 and 311 are the same contract. Maximum MW reported was 710, but that is MPC's total load. Subtracted value of GFA Nos. 309 and 317. 136.7 MW = share of Coyote plant; Service to NWPS = 46 MW;	Otter Tail Power Company	N/A	N/A
313	Carve Out until hearing resolved	0.00	Maximum MW already included in GFA Nos. 273, 309 and 317	Otter Tail Power Company	N/A	N/A
314	Carve Out until hearing resolved	0.00	Maximum MW already included in GFA Nos. 273, 309 and 317	Otter Tail Power Company	N/A	N/A
316	Carve Out until hearing resolved	0.00	Maximum MW already included in GFA Nos. 273, 309 and 317	Otter Tail Power Company	N/A	N/A
317	Carve Out until hearing resolved	250.00	Maximum MW reported as 710, but subtracted value of GFA Nos. 273 and 309.	Otter Tail Power Company	N/A	N/A
318	J & R	130.00	Maximum MW excludes OTP load because it is already included in OTP's network load under Midwest ISO OATT;	Otter Tail Power Company	Otter Tail Power	Otter Tail Power
320	Carve Out	0.00	GFA No. 274 and 320 are the same contract. Maximum Cumulative MW reported in GFA No. 274	Otter Tail Power Company	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
321	Carve Out	2.50	Maximum MW excludes OTP load because it is already included in OTP's network load under Midwest ISO OATT	Otter Tail Power Company	N/A	N/A
323	Carve Out	188.00	GFAs 323 & 390 are related three-party contracts.	Otter Tail Power Company	N/A	N/A
324	Already TEMT	0.00	Both parties, NSP & OTP, report the load as network load under Midwest ISO OATT	Otter Tail Power Company	N/A	N/A
331	Carve Out	423.00	Maximum MW listed in GFA No. 331 is a placeholder for GFA Nos. 331 - 341. 423 MW approximates Southern Illinois Power Coop generating capability as the best available information. 423 MW is not the maximum MWs transmitted under each relevant GFA.	Southern Illinois Power Coop	N/A	N/A
332	Carve Out			Southern Illinois Power Coop	N/A	N/A
333	Carve Out			Southern Illinois Power Coop	N/A	N/A
334	Carve Out			Southern Illinois Power Coop	N/A	N/A
335	Carve Out			Southern Illinois Power Coop	N/A	N/A
336	Carve Out			Southern Illinois Power Coop	N/A	N/A
337	Carve Out			Southern Illinois Power Coop	N/A	N/A
338	Carve Out			Southern Illinois Power Coop	N/A	N/A
341	Carve Out			Southern Illinois Power Coop	N/A	N/A
342	Option B	0.00	GFA Nos. 141,188 and 342 are all the same contract. GFA No. 342 covers service from Hoosier to SIGECO. Historic data shows 0 for Maximum MW	Southern Indiana Gas & Electric		
343	Option B	559.00	Maximum MW reported as 739. 180 MWs excluded from Maximum MW because it is for sales from Alcoa to SIGECO. Assumption is that delivery by Alcoa will be to Alcoa/SIGECO border and therefore there will be no service over Midwest ISO facilities.	Southern Indiana Gas & Electric	Southern Indiana Gas & Elec Co	Southern Indiana Gas & Elec Co
344	Carve Out	0.00	Maximum MW reported in companion GFA Nos. 144, 185, 200, 405 & 416	Wabash Valley Power	N/A	N/A
346	Option A/B	0.00	GFA Nos. 142 and 346 are the same contract; Maximum Cumulative MW reported in GFA No. 142	Wabash Valley Power		
347	Option A	0.00	GFA Nos. 144, 188 and 347 are all the same contract;	Wabash Valley Power		
352	J & R	2.73		Xcel - NSP	NSP	WAPA
354	J & R	1.85		Xcel - NSP	NSP	WAPA
355	Option B	5.63		Xcel - NSP	NSP	NSP
357	Option B	5.91		Xcel - NSP	NSP	NSP
358	Option B	10.93		Xcel - NSP	NSP	NSP
359	Option B	14.34		Xcel - NSP	NSP	NSP
360	Carve Out	8.62		Xcel - NSP	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
361	J & R	2.50		Xcel - NSP	NSP	WAPA
362	Option B	247.00	Maximum MW is largest capacity listed in historic data provided for MPPA load.	Xcel - NSP	Minnesota Muni Pwr Agency	Minnesota Muni Pwr Agency
363	Option B	1.97		Xcel - NSP		
364	Carve Out	8.07		Xcel - NSP	N/A	N/A
365	Carve Out	1.93		Xcel - NSP	N/A	N/A
366	J & R	0.59		Xcel - NSP	Northwestern Wisconsin Elec Co	Northwestern Wisconsin Elec Co
367	Carve Out	200.00		Xcel - NSP	N/A	N/A
368	Carve Out	200.00	Maximum MW reported 200+200 MWs, but that double counts the MW for this summer/winter exchange	Xcel - NSP	N/A	N/A
369	Carve Out	300.00	Maximum MW is taken from 1995-2014 data	Xcel - NSP	N/A	N/A
370	Carve Out	50.00	Maximum MW reported has 4 sink points of 25MW, but that double counts contract capacity since the sink points vary by season (summer/winter)	Xcel - NSP	N/A	N/A
371	Will Expire	0.00	To expire before 3/1/05	Xcel - NSP		
372	Option B	62.00		Xcel - NSP	Wisconsin Public Pwr	Wisconsin Public Pwr
373	Option B	123.00		Xcel - NSP	Wisconsin Public Pwr	Wisconsin Public Pwr
374	J & R	0.00		Xcel - NSP	Xcel	Xcel
375	Convert to TEMT	0.00	GFA No. 375 and 376 are related; Intend to convert to TEMT service; Maximum Cumulative MW is listed for GFA No. 376	Xcel - NSP	N/A	N/A
376	Convert to TEMT	2272.50	GFA No. 375 and 376 are related; Intend to convert to TEMT service; Maximum Cumulative MW is covered by GFA No. 376	Xcel - NSP	N/A	N/A
377	J & R	214.88		Xcel - NSP	NSP	NSP
378	Option B	1162.00	GFA Nos. 378 and 392 are related; Maximum Cumulative MW reported in GFA No. 378	Xcel - NSP	NSP	NSP
379	J & R	169.00		Xcel - NSP	Central Minnesota Muni Pwr	Central Minnesota Muni Pwr
381	J & R	7.20		Xcel - NSP	NSP	NSP
382	J & R	14.98		Xcel - NSP	NSP	NSP
383	J & R	9.14		Xcel - NSP	NSP	NSP
384	J & R	2.74		Xcel - NSP	NSP	NSP
385	J & R	2.54		Xcel - NSP	NSP	NSP
386	J & R	6.73		Xcel - NSP	NSP	NSP
387	J & R	3.61		Xcel - NSP	NSP	NSP
388	J & R	2.51		Xcel - NSP	NSP	NSP
389	Carve Out	0.00		Xcel - NSP	N/A	N/A
390	Carve Out	0.00	GFAs 323 & 390 are related three-party contracts. Maximum Cumulative MW reported in GFA No. 323.	Xcel - NSP	N/A	N/A
391	Carve Out	36.75		Xcel - NSP	N/A	N/A

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
392	Option B	0.00	GFA Nos. 378 and 392 are related; Maximum Cumulative MW reported in GFA No. 378	Xcel - NSP	Southern Minnesota Muni Pwr Agency	Southern Minnesota Muni Pwr Agency
394	Carve Out	1.30		Alliant Energy - IPL	N/A	N/A
395	Carve Out	102.50		Alliant Energy - IPL	N/A	N/A
399	Option A	0.00	GFA Nos. 399 and 417 are the same contract. Maximum Cumulative MW included in related GFA No. 188.	Cinergy - PSI		
401	J & R	129.00		GridAmerica - Ameren	Ameren	Ameren
403	J & R	62.00	Maximum MW excludes 38 MW associated with entitlement capacity Associated provides to Ameren	GridAmerica - Ameren	Associated Electric Coop / Union Elec	Associated Electric Coop / Ameren
405	J & R	58.00	GFA Nos. 405 and 427 are the same contract; Maximum Cumulative MW reported in GFA No. 405	GridAmerica - Ameren	Wabash	Wabash
406	Option B	0.00	GFA Nos. 222 and 406 are the same contract; GFA No. 448 is a companion; Maximum Cumulative MW reported in GFA No. 222.	GridAmerica - Ameren		
407	J & R	160.00		GridAmerica - Ameren	Union Electric	Ameren
409	J & R		Parties reported MWh. Directed to report MW.	GridAmerica - ATSI (First Energy)	FirstEnergy	FirstEnergy
410	J & R	50.00		GridAmerica - ATSI (First Energy)	FirstEnergy	FirstEnergy
411	J & R	677.50	Maximum MW does not include service from AMP-Ohio (City) to CEI because Midwest ISO facilities are not used	GridAmerica - ATSI (First Energy)	Cleveland Electric Illuminating Co	Cleveland Electric Illuminating Co
412	Option B	462.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	GridAmerica - ATSI (First Energy)	Ohio Edison Co / Penn Pwr Co	Ohio Edison Co / Penn Pwr Co
413	Option B	450.00		GridAmerica - ATSI (First Energy)	Ohio Edison Co	Mirant
414	Option B	352.00		GridAmerica - ATSI (First Energy)	Cleveland Electric Illuminating Co	FirstEnergy Service Co
415	J & R	0.00	GFA Nos. 410 and 415 are the same contract	GridAmerica - ATSI (First Energy)	FirstEnergy	FirstEnergy
416	Carve Out	0.00	GFA Nos. 416 and 428 same contract. Maximum Cumulative MW reported in GFA No. 428.	GridAmerica - NIPSCO	N/A	N/A
417	Option A	0.00	GFA Nos. 399 and 417 are the same contract. Maximum Cumulative MW included in related GFA No. 188.	Indiana Municipal Power Agency	Cinergy Services	Cinergy Services
418	Option A	463.00		LG&E Energy - KU	LG&E	LG&E
419	Option A	14.00		LG&E Energy - KU	LG&E	LG&E

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
420	Option A	62.00		LG&E Energy - KU	LG&E	LG&E
421	Carve Out	0.00	Related to GFA No. 257; Maximum Cumulative MW reported in GFA No. 257	Michigan Public Power Agency	N/A	N/A
422	Carve Out	0.00	Related to GFA No. 256; Maximum Cumulative MW reported in GFA No. 256	Michigan Public Power Agency	N/A	N/A
423	Carve Out	0.00	See 209 - same contract;	Michigan Public Power Agency	N/A	N/A
424	Carve Out	0.00	See 210 - same contract;	Michigan Public Power Agency	N/A	N/A
425	Carve Out	0.00	Maximum Cumulative MW reported in GFA No. 284	Minnesota Power	N/A	N/A
426	Option B	34.00	GFA Nos. 152, 216, 224, 412 and 426 are all the same contract	Southern Indiana Gas & Electric	Southern Indiana Gas & Elec Co	Southern Indiana Gas & Elec Co
427	J & R	0.00	GFA Nos. 405 and 427 are the same contract; Maximum Cumulative MW reported in GFA No. 405	Wabash Valley Power	Wabash	Wabash
428	Carve Out	328.00	GFA Nos. 416 and 428 are the same contract. Maximum Cumulative MW reported in GFA No. 428.	Wabash Valley Power	N/A	N/A
430	Carve Out	19.00		Cinergy - PSI	N/A	N/A
431	Carve Out	13.82		Xcel - NSP	N/A	N/A
432	J & R	0.86	reported by parties in KW	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
433	J & R	1.26	reported by parties in KW	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
434	J & R	0.37		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
435	J & R	2.62		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
436	J & R	0.13		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
437	J & R	0.00	Load included in OTP's network service under Midwest ISO OATT	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
438	J & R	0.00	Load included in OTP's network service under Midwest ISO OATT	Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
439	J & R	0.04		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
440	J & R	0.43		Otter Tail Power Company	Otter Tail Pwr	Otter Tail Pwr
441	Option B	8.00		City of Columbia, Water & Light Department (Columbia, MO)	Associated Electric Coop	Associated Electric Coop
442	Option B	20.00		City of Columbia, Water & Light Department (Columbia, MO)	University Of Missouri	University of Missouri

Appendix B

GFA Number	Category	Maximum MWs Transmitted Under GFA	Explanation of Rational for Finding	Transmission Owner	Responsible Entity	Scheduling Entity
443	Option B	50.00		City of Columbia, Water & Light Department (Columbia, MO)	City of Fulton, MO	City of Fulton, MO
444	Option B	1005.40		City of Columbia, Water & Light Department (Columbia, MO)		
445	Option B	20.00		City of Columbia, Water & Light Department (Columbia, MO)	City of Columbia, Water & Light Department	City of Columbia, Water & Light Department
446	J & R	2695.00		GridAmerica - Ameren	Union Electric / Ameren	Ameren
447	J & R	20.00		GridAmerica - Ameren	Union Electric	Ameren
448	Carve Out	0.00	GFA Nos. 222 and 406 are the same contract; GFA No. 448 is a companion; Maximum Cumulative MW reported in GFA No. 222.	Illinois Power Co	N/A	N/A
449	Option B	40.00		Illinois Power Co	Commonwealth Edison Co (Exelon)	Commonwealth Edison Co (Exelon)
450	Carve Out until hearing resolved	0.00	Maximum Cumulative MW included in GFA Nos. 273, 309 and 317	Minnesota Power	N/A	N/A

(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

[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*).

REQUEST:

8. Refer to Dr. McNamara's testimony at page 14.

   a. Will LG&E and KU be required to offer excess capacity?

   b. If LG&E and KU are required to offer excess capacity, what price will they receive for that capacity?

   c. Is it possible that LG&E and KU could be required to offer their excess capacity at a price that is lower than their marginal cost to produce that power?

   d. Would it be reasonable to assume that if the market price is higher than LG&E's or KU's marginal cost to produce the power, they would offer the power into the market voluntarily?

RESPONSE:

a. LG&E and KU will be required to offer excess capacity only into the Midwest ISO's Day-Ahead Market and RAC process, and only to the extent this capacity has been designated by LG&E or KU as a Network Resource.

b. To the extent this excess capacity clears the Market, LG&E and KU will receive the Market clearing price.

c. No.

d. On average and over time it would be reasonable to assume that LG&E/KU would take advantage of the market price if it is higher than their marginal cost to produce the power; however, numerous factors influence commercial behavior over short time periods and in specific situations.

Witness: Ronald R. McNamara