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October 20, 2003

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PUBLIC SERVICE COMMISSION

Thomas M. Dorman
Executive Director
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40602—0615

Re: *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*

Dear Mr. Dorman:

Enclosed please find an original and ten (10) copies of Louisville Gas and Electric Company's and Kentucky Utilities Company's responses to the data requests proffered by the Commission and the Midwest Independent Transmission System Operator, Inc. ("MISO") on October 6, 2003, in the above-referenced docket. Also enclosed is a motion for confidential treatment governing certain information provided in response to MISO Request Nos. 9 and 11.

Should you have any questions concerning the enclosed, please do not hesitate to contact me directly at 502/627-2557.

Very truly yours,

Linda S. Portasik

Linda S. Portasik
Counsel for Louisville Gas and Electric Company and Kentucky Utilities Company

cc (w/enclosure): Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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OCT 20 2003

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

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY
TO THE FIRST DATA REQUEST OF COMMISSION STAFF
DATED OCTOBER 6, 2003

FILED: OCTOBER 20, 2003

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 1

Responding Witness: Paul W. Thompson/Michael S. Beer

Q-1. Refer to page 7 of the Testimony of Paul W. Thompson ("Thompson Testimony").

a. Provide the relevant portions of the presiding judge's November 26, 1999 decision finding that all "users of the grid" benefit equally from the operation of the Midwest Independent System Operator, Inc. ("MISO").

b. Provide the relevant portions of the Federal Energy Regulatory Commission's ("FERC") Opinion 453, which affirmed the judge's conclusion that MISO's Schedule 10 charges must be paid on behalf of existing bundled retail load.

A-1. a. Please see *Midwest Independent Transmission System Operator, Inc.*, 89 FERC ¶63,008 at 65,045 (slip op. at 12-13):

> *All of the Midwest ISO Participants' transmission customers will benefit* from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability of the transmission system. *Therefore, to ensure that retail load will properly bear a fair share of the Midwest ISO's costs,* all long-term firm, bundled retail, and grandfathered load should be included in the divisor in developing the Cost Adder. (Emphasis added.)

The quoted language ("all users of the grid") is taken directly from the FERC's order affirming the presiding judge's decision, *Midwest Independent Transmission System Operator, Inc.*, Opinion No. 453, 97 FERC ¶61,033 (slip op. at 7):

> The [FERC] will affirm the presiding judge's finding that the Midwest ISO Cost Adder must include all existing bundled load and any grandfathered wholesale load. *We agree with the presiding judge that all users of the grid operated by the Midwest*

> *ISO will benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability of the transmission system.* (Emphasis added.)

See also FERC Opinion No. 453-A, 98 FERC ¶61,141 (slip op. at 8):

> Intervenors [*e.g.*, LG&E and KU] fail to consider *the benefits all users of the regional grid will receive* when that grid is operated and planned by a single regional entity instead of multiple local entities whose goals may often conflict. As a result of this move to unified planning and operation of the regional grid, we expect to see more efficient siting of transmission facilities from the regional perspective; i.e., siting that follows need rather than arbitrary boundaries such as individual local service territories. This will result in enhanced reliability, *which will benefit all loads.* This is because the non-Midwest ISO-operated facilities, such as those connected to local generation, in this region are integrated with the facilities operated by the Midwest ISO. It is established Commission policy that an integrated transmission grid is cohesive network moving electricity in bulk. *Thus, all customers using that grid share in all costs of the grid, because they all benefit.* (Emphasis added.)

Despite FERC's inference that the cited "benefits" would inure equally to all MISO participants (in proportion to their load), its finding was not supported by record evidence, and is currently pending review before the United States Court of Appeals for the District of Columbia Circuit. Please see below and the Companies' response to Question 2.

b. Please see *Midwest Independent Transmission System Operator, Inc.*, Opinion No. 453, 97 FERC ¶61,033 (slip op. at 7) (quoted above). *See also* Opinion No. 453-A, 98 FERC ¶61,141 (slip op. at 8) (quoted above).

The Companies also note (with respect to subparts (a) and (b)) that the Kentucky Public Service Commission ("KPSC") has interpreted the referenced orders in the very manner described in Mr. Thompson's testimony. Please refer to the joint brief filed by the KPSC (with LG&E/KU and others) before the United States Court of Appeals for the District of Columbia Circuit on September 19, 2002, in Case No. 02-1121 ("KPSC Joint Brief"). For example, the KPSC expressly joined in the following argument raised in such Brief:

> **B. The *FERC's Imposition Of the ISO Cost Adder On Transmission Owners On Behalf of Bundled Load* Is Not Supported By Substantial Evidence, Ignores Without**

> **Explanation Conflicting Evidence, And Violates The Cost Causation Principle**. (Emphasis added.)
>
> The basis for FERC's conclusion in Opinion No. 453 *that bundled loads should bear most of the ISO's costs* is a single sentence. FERC simply states that it agrees with the Presiding Judge that "all users of the grid operated by the Midwest ISO will benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as [from] increased grid reliability of the transmission system." FERC fails to explain how, why, or the degree to which bundled retail customers would benefit from these factors, and cites no evidence to support any of these assertions. (Emphasis added; footnotes omitted.)

See KPSC Joint Brief at page 29, and note 46. *See also* Statement of Facts at page 17:

> On October 11, 2002, FERC issued Opinion No. 453. FERC affirmed the Presiding Judge's finding that the On October 11, 2001, FERC issued Opinion No. 453. *FERC affirmed the Presiding Judge's finding that the ISO Cost Adder must be paid by all existing bundled retail load* and any grandfathered wholesale load. FERC's principal support for this conclusion was its acceptance of the Presiding Judge's unsupported conclusion that "all users of the grid" will benefit from "the Midwest ISO's operational and planning responsibilities . . . as well as increased grid reliability of the transmission system." Like the Presiding Judge, FERC neither referred to nor analyzed any of the record evidence. (Citations/footnotes omitted; emphasis added.)

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 2

Responding Witness: Linda S. Portasik

Q-2. Refer to pages 8-9 of the Thompson Testimony. Provide the procedural status of LG&E's and KU's appeal of FERC's Opinion 453 pending before the United States Court of Appeals for the District of Columbia.

A-2. The United States Court of Appeals for the District of Columbia Circuit issued an order on September 26, 2003, consolidating Case No. 02-1122 (governing the Court's review of FERC Order Nos. 453 and 453-A) with Case Nos. 03-1236 and 03-1256 (governing the Court's review of FERC's subsequent order on remand and order denying rehearing, as initiated by petitions for review filed by the MISO transmission owners and this Commission, respectively.) In that same order, the Court established a briefing schedule calling for initial joint briefs by petitioners and supporting intervenors on November 10, 2003. Final briefs by all parties are currently due on January 21, 2004. The Court has not yet set a date for oral argument.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 3

Responding Witnesses: Paul W. Thompson/Michael S. Beer

Q-3. Refer to the first full paragraph on page 15 of the Thompson Testimony, which states that there is currently no practical means to minimize MISO's expenditures consistent with good business practice.

a. By "good business practice," does Mr. Thompson mean, either in a bilateral or unilateral manner, something outside the regulatory oversight of FERC? Explain the response.

b. To date, what actions has FERC taken in terms of reviewing or monitoring MISO's expenditures to determine whether they are reasonable and necessary? Has FERC initiated any formal or informal proceedings relating to MISO expenditures? Explain the response.

A-3.

a. Yes. Mr. Thompson refers in this paragraph to the means afforded to the Companies (and indeed to all MISO stakeholders) via the governance structure of MISO. It is difficult for the Companies to affect MISO's activities and expenditures within that structure for several reasons.

First, the existing governance structure gives weight to the input of a large number of stakeholder groups. These include transmission owners, independent transmission companies, independent power producers/exempt wholesale generators, municipalities/cooperatives/other transmission-dependent utilities, power marketers/brokers, eligible end-user customers, state regulatory authorities, public consumer groups, and environmental and other stakeholder groups. The number of stakeholders has increased since the MISO was founded in 1996.

Second, the interests of these stakeholder groups are very diverse. MISO is arguably faced with the challenge of being everything to everyone. LG&E/KU believe that MISO is still evolving; MISO stakeholders often disagree as to exactly *how* MISO should evolve. The views of the MISO stakeholders have grown more diverse since MISO was founded in 1996—particularly in light of the developing SMD and the proposed MISO implementation thereof.

Third, the lack of other viable, existing RTO alternatives in the Midwest creates a barrier to exit that exacerbates the aforementioned governance issues. For these reasons, LG&E/KU lack a practical, timely means for tightly managing MISO's activities and minimizing MISO expenditures within the existing MISO governance framework.

b. To date, the FERC has exercised only limited oversight of MISO's expenditures. Although recognizing the concerns expressed by MISO's customers regarding MISO's increasing expenditures, the FERC has refused to require MISO to submit formal applications for cost recovery under FPA Section 205. Instead, MISO must submit only "informational filings . . . sufficient to provide advance notice of potential cost issues that the parties could raise in appropriate filings with the Commission." *Ameren Services Co., et al.*, 105 FERC ¶61,018, slip op. at 4 (2003) (*citing* 104 FERC ¶61,097 (2003)).

The Companies do not believe an "informational filing" equates to a formal filing submitted under FPA Section 205. First, applications submitted under FPA Section 205 must include detailed cost support (specified by regulation) sufficient to allow thorough cost review. The information included in an "informational filing" apparently consists of whatever information MISO has in hand. *See, e.g.*, MISO Motion for Clarification, Case Nos. ER02-2233-002, *et al.*, June 16, 2003, at 4 (urging FERC not to require formal Section 205 filing because MISO lacks the information required to support such filing). Second, a formal Section 205 filing triggers statutory protections not otherwise afforded in the context of an informational filing, *i.e.*, Section 205 refund protection. It is the Companies understanding that, should they elect to challenge the prudence of one or more of MISO's expenditures, as identified in an "informational filing," they must seek redress under FPA Section 206, which imposes on MISO a more limited statutory refund obligation.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 4

Responding Witness: Mark S. Johnson/Mathew J. Morey

Q-4. Refer to Exhibit PWT-2, page 7 of 9, which refers to MISO implementing Schedules 16 and 17, subject to refund and paper hearing procedures.

a. Explain whether LG&E and KU have incurred any expenses to date under Schedules 16 and 17.

b. Provide a schedule showing separately the monthly expenses incurred by LG&E and KU under Schedules 16 and 17 to date.

c. Assuming they remain in MISO, provide the annualized level of expense projected to be incurred separately by LG&E and KU under Schedules 16 and 17 going forward.

A-4.

a. Neither LG&E nor KU have incurred any costs to date for Schedules 16 and 17.

b. n/a

c. Table Q-4 (c) 1, Table Q-4 (c) 2 and Table Q-4 (c) 3 below summarize the annualized level of expense projected to be incurred separately by LG&E and KU under Schedules 16 and 17 going forward for the period 2005 to 2010. The basis for these annualized estimates is the annual costs of Schedule 16 and 17 for the combined Companies as presented in Table 3.1 (at p. 44) of the Cost-Benefit Analysis. The combined costs are allocated between the Companies (LG&E and KU) and off-system sales ("OSS") on the basis of load ratio shares given the 2002 projections of energy sales and sales for resale for the period 2005 to 2010.

Table Q-4 (c) 1. Allocation between LG&E and KU of Annualized Schedule 16 Charges

	SCHEDULE 16 Charges ($)				
	Rate (cents/MWh)	KU/1	LG&E/1	OSS	COMBINED
2005	2.89	740,411	427,714	-	1,168,125
2006	2.97	791,281	454,230	-	1,245,510
2007	2.81	770,955	440,495	-	1,211,450
2008	2.72	761,541	432,985	-	1,194,526
2009	1.96	562,189	318,076	-	880,265
2010	1.96	575,315	323,908	-	899,223

Table Q-4 (c) 2. Allocation between LG&E and KU of Annualized Schedule 17 Charges

	SCHEDULE 17 Charges ($)				
	Rate (cents/MWh)	KU/[2]	LG&E/[2]	OSS/[3]	COMBINED
2005	3.51	899,253	519,473	123,361	1,542,087
2006	3.57	951,135	545,993	115,952	1,613,081
2007	3.43	941,059	537,686	100,311	1,579,057
2008	3.35	937,927	533,272	98,344	1,569,544
2009	2.57	737,156	417,068	75,703	1,229,928
2010	2.57	754,368	424,716	75,877	1,254,961

Table Q-4(c) 3. Sum of Annualized Schedule 16 and 17 Charges for LG&E and KU

	Total Schedule 16 and Schedule 17 Charges ($)				
		KU	LG&E	OSS	COMBINED
2005		1,639,664	947,187	123,361	2,710,211
2006		1,742,416	1,000,223	115,952	2,858,591
2007		1,712,014	978,181	100,311	2,790,506
2008		1,699,468	966,257	98,344	2,764,070
2009		1,299,345	735,144	75,703	2,110,192
2010		1,329,682	748,624	75,877	2,154,184

Notes
1 Rate applied to energy
2 Rate applied to energy only; if applied to generation also multiply by 2
3 Rate applied to generation only

**LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY**

CASE NO. 2003-00266

**Response to First Data Request of Commission Staff
Dated October 6, 2003**

Question No. 5

Responding Witness: Mark S. Johnson/Mathew J. Morey

Q-5. Refer to the August 31, 2003 Final Report of the Barrington-Wellesley Group, Inc., filed in Case Nos. 2003-00334 and 2003-00335 [footnotes omitted], pages I-13 and I-14, which discusses the $18.9 million in MISO-related costs incurred by LG&E and KU during 2002.

a. Provide the date that LG&E and KU began incurring expenses under MISO's Schedule 10, the monthly amount of Schedule 10 expenses that each has been billed to date, and the total amount of such expenses deferred for later billing by MISO.

b. Identify any other MISO charges assessed to LG&E and KU and provide a schedule of the monthly amount of such charges billed or deferred to each to date.

c. Provide the date that LG&E and KU began receiving MISO-related revenues and a schedule of the monthly amount received by each in 2002. Identify each service provided by LG&E and KU which generated MISO-related revenues.

d. Provide a schedule of the monthly amount of transmission revenues received separately by LG&E and KU to date as MISO transmission owners.

e. Explain whether the responses to 4(a), 4(b), and 5(a) through (d) identify the total financial impact that MISO has had on LG&E and KU.

f. Describe any other costs, charges, revenues, etc. that should be factored into an analysis of the financial impact on LG&E and KU of MISO membership.

g. Based on the overall level of MISO-related costs presently incurred by LG&E and KU, provide the current estimates of the annual ongoing level of MISO related costs for LG&E and KU. Provide a narrative explanation of the response and include all supporting calculations, workpapers, etc.

h. Based on information currently available to LG&E and KU, what is the current estimate of the annual ongoing level of MISO-related revenues for LG&E and KU. Provide a narrative explanation of the response and include all supporting calculations, workpapers, etc.

A.5.

a. LG&E/KU started incurring expenses under Schedule 10 in January 2002. *See* attached. MISO's latest comparative balance sheet shows deferred regulatory assets of $94,503,910 as of September 2003. This amount includes, but is not limited to, Schedule 10 deferrals.

b. *See* attached.

c. LG&E/KU began receiving revenues for use of the transmission system assets under the MISO OATT in February 2002. In addition to transmission service, LG&E/KU is compensated for its provision of service under Ancillary Services Schedule 1 (Scheduling, System Control and Dispatch Service) and Schedule 2 (Reactive Supply and Voltage Control from Generation Sources Service).

d. *See* attached.

e. Yes.

f. The current estimates of the ongoing annual MISO related costs for LG&E and KU have been developed in the Cost-Benefit Analysis prepared by Christensen Associates (attached to the testimony of Mathew J. Morey as Exhibit MJM-1). The supporting calculations and workpapers that underlie those estimates have been supplied in response to Question 9 (*i.e.*, Q-9) of the Initial Data Request of the Midwest Independent Transmission System Operator, Inc., October 6, 2003.

In the Cost-Benefit Analysis, the summary of the current estimates of the ongoing annual MISO related costs (i.e., Schedules 10, 16 and 17 charges) for the Companies can be found in Table ES.1 (at p. v), and a more detailed breakdown of those cost estimates can be found in Section 4, Table 4.1 (at p. 54). Discussion of the estimated expense for Schedule 10 can be found in Section 3.10, Subsection 3.10.1, (at pp. 41-42) of the Cost-Benefit Analysis. Further discussion of estimated expense for Schedule 16 can be found in Section 3.10, Subsection 3.10.1 (at p. 42-43) of the Cost-Benefit Analysis. Further discussion of the estimated expense for Schedule 17 can be found in Section 3.10, Subsection 3.10.1 (at p. 43). A summary of the estimated annual expenses (expressed in nominal dollars) for all three schedule charges can be found in Table 3.2 (at p. 44) of the Cost-Benefit Analysis.

The Companies expect to incur expenses for legal and regulatory services in support of the Companies' participation in the MISO that would exceed those costs for similar services if the Companies were to withdraw from MISO and operate as a standalone system. The estimated annual expenses equal $0.9 million if the Companies remain a MISO member.

The Companies also expect to have an additional annual expense of paying the increased Attachment O-based FERC fees, estimated to be $1.34 million. The estimated annual costs for the Companies to conduct trading in the MISO Day 2 market include: $0.4 million per year for staffing, training and consultants; $5.25 million per year for transmission-related charges for off-system trades; $0.50 million per year for miscellaneous uplift charges; and $2.0 million per year for charges allocated to the Companies to recover the costs of congestion-based MISO charges allocated to the Companies.

g. See answer to (f) above.

h. The estimated annual revenues that the Companies would receive from participating as a member of MISO during the period 2005-2010 that are strictly related to membership have been documented in the Cost-Benefit Analysis. They appear in Section 4.0, Table 4.1 (at p. 44) under the heading of "Lost Revenues." There are four categories of these revenues that would be expected to be sacrificed if the Companies were to withdraw from MISO by the end of 2004 and operate as a standalone system. If the Companies were to remain in MISO, these revenues would not be sacrificed, and would not be considered "Lost Revenues." First, the Companies expect to receive transmission revenues in the period 2005-2006 that represent partial compensation to LG&E and KU for the elimination of pancaked transmission rates within the MISO footprint and the elimination of through and out rates between MISO and PJM (i.e., inter-regional pancaking). Second, the Companies expect to receive a load-ratio share based allocation of the revenues received by MISO for its sale of excess FTRs. That allocation is expected to average $2.0 million per year. Third, the Companies expect to receive $2.0 million per year as the load-ratio based share of revenues MISO receives for Schedules 1, 2, 7, 8, 9, and 14. Fourth, as a member of MISO, the Companies expect an additional $1.0 million per year in transmission revenue associated with the higher rates in the MISO OATT for Schedules 1 and 9. These rates are higher than LG&E's and KU's Schedule 1 and 9 rates otherwise applicable under transmission contracts with TVA and East Kentucky Power Cooperative. In the latter regard, however, the Companies contemplate receiving comparable revenue from East Kentucky through a general rate filing at FERC (currently ongoing), regardless of whether they remain in or exit MISO.

MISO Expenses

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	TOTAL 2002
LG&E													
Schedule 10	235,628	213,247	229,548	251,970	349,510	318,345	159,236	250,957	268,076	346,626	227,621	216,503	3,067,268
Schedule 1		28,197	25,447	25,746	77,457	32,203	18,197	13,252	32,177	68,420	46,950	72,247	440,291
Schedule 2		83,283	73,007	66,038	155,905	60,467	36,128	29,584	72,550	160,386	93,923	151,181	982,453
Schedule 7		679,006	538,343	484,159	1,492,246	541,970	424,792	267,000	544,690	1,295,145	889,641	1,313,447	8,470,639
Schedule 8		67,729	109,716	69,785	22,491	1,676	12,576	46,346	143,193	154,435	151,458	211,455	990,860
Schedule 11		0	0	1,163	0	0	0	3	0	0	0	1,076	2,242
TOTAL LG&E	**235,628**	**1,071,463**	**976,061**	**898,861**	**2,097,609**	**954,661**	**650,930**	**607,142**	**1,060,887**	**2,025,011**	**1,409,593**	**1,965,908**	**13,953,754**
KU (Total Company Expenses)													
Schedule 10	204,906	374,305	432,136	352,269	395,355	458,003	259,806	360,820	396,373	330,277	373,368	362,263	4,299,881
Schedule 1		3,233	8,786	3,938	3,352	23,967	13,046	19,053	20,982	0	3,240	16,487	116,084
Schedule 2		9,548	25,206	10,100	6,747	45,003	25,903	42,535	47,309	0	6,482	34,500	253,333
Schedule 7		77,841	185,865	74,047	64,582	403,359	304,565	383,886	355,317	0	61,398	299,735	2,210,597
Schedule 8		7,764	37,880	10,673	973	1,247	9,017	66,635	93,375	0	10,453	48,255	286,273
Schedule 11		0	0	178	0	0	0	4	0	0	0	141	323
TOTAL KU	**204,906**	**472,690**	**689,872**	**451,205**	**471,010**	**931,579**	**612,339**	**872,933**	**913,357**	**330,277** (a)	**454,941**	**761,382**	**7,166,490**
LG&E and KU Combined													
Schedule 10	440,535	587,552	661,683	604,239	744,865	776,348	419,043	611,778	664,449	676,903	600,989	578,766	7,367,149
Schedule 1	0	31,430	34,233	29,683	80,809	56,171	31,243	32,304	53,159	68,420	50,190	88,734	556,376
Schedule 2	0	92,831	98,212	76,138	162,653	105,470	62,031	72,119	119,859	160,386	100,405	185,681	1,235,786
Schedule 7	0	756,848	724,208	558,206	1,556,829	945,328	729,357	650,886	900,207	1,295,145	951,039	1,613,183	10,681,236
Schedule 8	0	75,493	147,596	80,458	23,464	2,923	21,594	112,981	236,568	154,435	161,911	259,710	1,277,133
Schedule 11	0	0	0	1,341	0	0	0	7	0	0	0	1,216	2,565
TOTAL LG&E & KU	**440,535**	**1,544,153**	**1,665,933**	**1,350,065**	**2,568,619**	**1,886,240**	**1,263,268**	**1,480,075**	**1,974,243**	**2,355,288**	**1,864,534**	**2,727,290**	**21,120,244**

(a) During October expense allocation was 100% for LG&E.

MISO REVENUE

	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	TOTAL 2002
LG&E												
Schedule 7,8 and 14	304,800	197,176	203,707	460,546	374,883	380,260	362,519	415,779	493,446	467,934	533,235	4,194,285
Schedule 1		2,420	24,247	45,148	34,432	32,956	21,455	31,553	39,556	36,936	33,583	302,287
Schedule 2		31,362	21,303	67,882	52,012	48,713	54,604	51,344	66,945	67,387	59,616	521,167
TOTAL LG&E	**304,800**	**230,958**	**249,258**	**573,576**	**461,327**	**461,928**	**438,578**	**498,676**	**599,947**	**572,257**	**626,434**	**5,017,739**
KU (Total Company Revenues)												
Schedule 7,8 and 14	703,858	441,068	464,624	1,050,432	855,049	867,312	826,848	948,326	1,125,470	1,067,230	1,213,216	9,563,431
Schedule 1		12,866	18,509	51,818	26,284	25,157	16,378	24,086	30,196	28,195	33,583	267,072
Schedule 2		12,922	16,262	34,464	39,704	37,185	41,682	39,194	51,103	51,440	59,616	383,572
TOTAL KU	**703,858**	**466,856**	**499,395**	**1,136,714**	**921,036**	**929,654**	**884,908**	**1,011,606**	**1,206,769**	**1,146,865**	**1,306,415**	**10,214,075**
LG&E and KU Combined												
Schedule 7,8 and 14	1,008,658	638,244	668,331	1,510,978	1,229,932	1,247,571	1,189,367	1,364,105	1,618,916	1,535,164	1,746,451	13,757,716
Schedule 1 REV	0	15,286	42,757	96,966	60,716	58,113	37,832	55,640	69,752	65,132	67,166	569,359
Schedule 2 REV	0	44,285	37,565	102,346	91,715	85,898	96,287	90,537	118,048	118,827	119,232	904,739
TOTAL LG&E & KU	**1,008,658**	**697,814**	**748,653**	**1,710,290**	**1,382,363**	**1,391,582**	**1,323,486**	**1,510,282**	**1,806,715**	**1,719,123**	**1,932,849**	**15,231,814**

(a) *MISO Revenue adjustment for Feb02 to Feb03 for rebillings.*

MISO Expenses

	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	TOTAL Jan - Aug 03
LG&E									
Schedule 10	320,614	200,541	167,988	144,866	141,876	261,962	199,513	235,529	1,672,888
Schedule 1	79,304	43,783	73,202	65,698	39,559	68,275	65,211	73,684	508,716
Schedule 2	178,573	101,407	159,307	146,438	83,300	138,841	130,266	153,961	1,092,094
Schedule 7	1,019,881	251,658	428,716	339,248	84,842	196,115	97,157	211,798	2,629,415
Schedule 8	469,570	569,453	917,321	864,752	610,575	962,420	1,043,798	1,095,045	6,532,934
Schedule 11	2,208	94,510	10,641	3,152	31,070	0	14,607	(87,580)	68,608
TOTAL LG&E	**2,070,150**	**1,261,352**	**1,757,174**	**1,564,154**	**991,222**	**1,627,813**	**1,550,552**	**1,682,437**	**12,504,654**
KU (Total Company Expenses)									
Schedule 10	518,758	366,492	235,852	175,305	194,509	313,906	254,569	253,423	2,312,815
Schedule 1	30,717	6,866	6,663	22,971	9,419	17,017	24,148	12,336	130,138
Schedule 2	69,169	15,903	14,501	51,201	19,833	34,605	48,238	25,776	279,227
Schedule 7	395,040	39,467	39,024	118,615	20,201	48,880	35,978	35,460	732,664
Schedule 8	181,883	89,306	83,499	302,353	145,377	239,875	386,525	183,334	1,612,152
Schedule 11	346	14,822	969	1,102	7,398	0	5,409	(14,663)	15,383
TOTAL KU	**1,195,913**	**532,857**	**380,508**	**671,546**	**396,737**	**654,283**	**754,868**	**495,667**	**5,082,378.32**
LG&E and KU Combined									
Schedule 10	839,372	567,033	403,840	320,171	336,385	575,868	454,082	488,952	3,985,703
Schedule 1	110,021	50,650	79,865	88,669	48,978	85,292	89,359	86,020	638,854
Schedule 2	247,742	117,310	173,808	197,639	103,133	173,446	178,505	179,737	1,371,320
Schedule 7	1,414,921	291,125	467,739	457,863	105,043	244,995	133,135	247,258	3,362,079
Schedule 8	651,453	658,759	1,000,820	1,167,105	755,952	1,202,296	1,430,324	1,278,379	8,145,086
Schedule 11	2,554	109,332	11,609	4,254	38,468	0	20,016	(102,242)	83,990
TOTAL LG&E & KU	**3,266,062**	**1,794,209**	**2,137,682**	**2,235,701**	**1,387,959**	**2,281,896**	**2,305,420**	**2,178,104**	**17,587,033**

(a) During October expense allocation was 100% for LG&

MISO REVENUE

	Jan-03	Feb-03	Mar-03		Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	TOTAL Jan - Sep 03
LG&E											
Schedule 7,8 and 14	601,621	340,490	(103,896)		470,213	326,230	502,290	549,402	514,110	566,811	3,767,270
Schedule 1	56,262	31,393	35,752		45,353	31,663	51,072	54,712	50,241	56,514	412,962
Schedule 2	91,142	56,463	63,150		78,223	60,070	92,551	100,977	89,805	99,568	731,951
TOTAL LG&E	**749,026**	**428,346**	**(4,994)**		**593,789**	**417,963**	**645,913**	**705,091**	**654,156**	**722,893**	**4,912,183**
KU (Total Company Revenues)											
Schedule 7,8 and 14	1,372,194	776,603	(236,969)		1,072,480	744,328	1,145,560	1,253,097	1,172,602	1,292,805	8,592,700
Schedule 1	42,948	23,964	27,291		34,621	24,170	38,986	41,765	38,352	43,140	315,238
Schedule 2	69,574	43,102	48,206		59,712	45,855	70,650	77,082	68,553	76,006	558,740
TOTAL KU	**1,484,716**	**843,668**	**(161,472)**		**1,166,813**	**814,354**	**1,255,196**	**1,371,943**	**1,279,508**	**1,411,952**	**9,466,677.53**
LG&E and KU Combined											
Schedule 7,8 and 14	1,973,815	1,117,092	(340,865)		1,542,692	1,070,558	1,647,850	1,802,498	1,686,712	1,859,616	12,359,970
Schedule 1 REV	99,210	55,357	63,043		79,974	55,834	90,058	96,477	88,594	99,654	728,200
Schedule 2 REV	160,717	99,565	111,355		137,936	105,925	163,201	178,059	158,358	175,575	1,290,691
TOTAL LG&E & KU	**2,233,742**	**1,272,014**	**(166,467)**	**(a)**	**1,760,602**	**1,232,317**	**1,901,109**	**2,077,034**	**1,933,664**	**2,134,845**	**14,378,860**

(a) MISO Revenue *adjustment for* Feb02 to Feb03 for re

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 6

Responding Witness: Mark S. Johnson/Martyn Gallus

Q-6. Have LG&E and KU performed an analysis to determine how much more or less revenues they have received as members of MISO versus not being members? If yes, provide the results. If no, prepare such an analysis using currently available information.

A-6. No, the Companies have not prepared a detailed analysis comparing specifically the actual revenues the Companies currently receive in total (by virtue of their MISO membership) to the revenues they would have received as non-MISO members during this same period. Such an analysis would not be meaningful because the calculation of revenues that the Companies would historically have received if not MISO members would be highly speculative. It is possible, however, to compare the historical revenues received prior to membership in MISO with the current revenues received as MISO members. From a transmission-only standpoint (i.e. not including off-system sales), the Companies' revenues and expenses for the periods 2001 (pre-MISO operation), 2002 and 2003 to date are listed below:

2001 Open-Access Transmission revenues: $4,076,755 (excludes bundled load, off-system sales)
2001 Open-Access Transmission expenses: $0 (excludes bundled load, off-system sales)

2002 MISO Open Access Transmission revenues: $15,231,814
2002 MISO Open Access Transmission expenses: $21,120,244

2003 MISO Open Access Transmission revenues: $14,378,860
2003 MISO Open Access Transmission expenses: $17,587,033

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 7

Responding Witness: Mathew J. Morey

Q-7. Explain in detail the anticipated impact on the revenues and expenses of LG&E and KU resulting from MISO's adoption of LMP pricing.

A-7. There are two areas of revenue and expense that conceivably could be affected by MISO's adoption of LMP pricing: transmission and off-system trades. Because there are two options that are under serious consideration by the Companies in this proceeding (remain a member of MISO and operate as a standalone system), we will address each of these separately and in turn.

The adoption of LMP pricing, set within the context of a bid-based, security constrained economic dispatch, means that the market clearing price for energy at each node will be equal to the marginal opportunity cost of generation at each node (which in turn equals the marginal benefit of demand at each node). When the grid is unconstrained, the nodal prices will reflect differences due to losses. When the grid is constrained, the nodal prices will reflect differences due to losses plus the marginal cost of redispatch (these nodal differences are called congestion rents). The adoption of LMP pricing in MISO thus changes the process by which the price will be determined for short-term spot market trades. It also changes the way in which transmission use is priced (as opposed to how access to the grid is priced).

Thus, LG&E/KU do not anticipate that MISO's adoption of LMP pricing will materially affect the Companies' transmission revenues regardless of the option pursued ultimately because it does not directly affect the determinants of the Companies' transmission revenues. With regard to transmission expenses, the Companies do not expect to see a material change in the cost of operating their transmission system (in either case) resulting from the adoption of LMP pricing. However, in the case where the Companies remain a member of MISO, adoption of LMP pricing could result in an additional expense associated with congestion charges. The Companies do not expect to receive financial transmission rights (FTRs) that will hedge their exposure to congestion costs for 100 percent of the hours (and they naturally may not want to attempt to hedge 100 percent of their load in all hours of the year). Therefore, if LG&E/KU are not fully hedged, it is possible that the Companies will be faced with an expense associated with their share of uncovered congestion rents in MISO. The magnitude of the expense will depend on many factors, including the allocation of FTRs among transmission owners and other participants that will satisfy a feasibility condition, actual power flows and market clearing prices determined by bids and offers in the spot market. Given that none of these factors is known at this time, it is quite difficult to estimate what this additional expense will be for the Companies.

With respect to off-system trades, if the Companies choose to trade at the border bus, as suggested and assumed in the Cost-Benefit analysis, energy will be bought and sold at the price set at the appropriate reference node. It is very difficult to say at this time what the actual impact will be on the cost of power purchases. The nodal (*i.e.*, border bus) price could be higher on average than the price the Companies have paid historically for power from MISO sources, or it could be lower on average. Similarly, if the Companies are selling power at the border bus, they could see a price that is higher on average than prices they have been paid historically for off-system sales (*e.g.*, economy sales), or they could see a price that is lower. So long as the Companies are trading at the border bus, the effect of LMP pricing and LMP-based pricing of congestion and losses is limited to the determination of the border bus price and its impact on the cost of purchased power or the price received for power sales. However, if the Companies engaged in point-to-point transactions in MISO beyond the border, it is possible that LMP-based pricing of congestion and losses could affect both off-system sales revenues and off-system purchases. It is not possible to know in what direction the effects would have an impact.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 8

Responding Witnesses: Paul W. Thompson/Michael S. Beer

Q-8. Refer to pages 14-16 of the Thompson Testimony and pages 10-11 of the Testimony of Michael S. Beer ("Beer Testimony"). Mr. Thompson discusses LG&E and KU wanting the Commission's full support of their pursuit of a voluntary exit from MISO, but not a Commission requirement to do so. Mr. Beer describes LG&E's and KU's request for authorization in this proceeding to establish a regulatory asset for the MISO exit fee. Mr. Beer also discusses LG&E's and KU's intentions for future rate recovery of their MISO-related costs. Provide clarification of precisely what LG&E and KU are requesting from the Commission in this proceeding.

A-8. LG&E and KU clarify their position as follows: if the Commission determines, based on the evidence of record in this case, that (i) the costs of the MISO membership exceed the benefits of the MISO membership and (ii) the Companies should pursue an exit from MISO, then LG&E and KU request that the Commission direct the Companies to pursue such withdrawal, recognizing that the Companies cannot exit without having first obtained requisite FERC approval. In this regard, the order must acknowledge the Companies' obligation to obtain FERC approval prior to exit, and afford the Companies ample opportunity to secure such approval on reasonable terms. LG&E and KU also request that the Commission's order recognize that the Companies are entitled to (i) full rate recovery of all ongoing MISO-related costs pending their receipt of a final FERC order approving such withdrawal; and (ii) full recovery of any exit fee imposed on them as a consequence of such withdrawal and were not required to obtain the Commission's prior approval before joining MISO.

LG&E and KU believe strongly that the above-noted conditions to exit, as described by Mr. Thompson in his testimony (at pages 14-16), are essential (a) to make the Companies whole for costs incurred in connection with their membership in MISO (which membership the Commission cited with favor, and effectively imposed on the Companies through the merger commitments in Case Nos. 2000-095 and 2001-104); and (b) to allow the Companies to avoid the inherent uncertainties and costs attendant to conflicting state and federal regulatory directives. More specifically in the latter regard, an order by this Commission directing exit by a date certain without the requested conditions would necessarily create such conflict unless the Companies were able to obtain a consistent FERC order by that date, which may not be possible. *See* the Companies' response to Question 10. Sound regulatory policy and principles of corporate integrity *counsel strongly against* leaving the Companies -- answerable as regulated entities both to this Commission and the FERC -- in a position of untenable uncertainty as to what they must do to comply with the law.

Mr. Beer's testimony at the above-referenced pages describes the Companies' two-pronged proposal for recovering MISO-related costs "if the KPSC accepts the Companies' exit proposal as described by Mr. Thompson." MISO-related costs include (i) the exit fee imposed by MISO pursuant to the MISO Transmission Owners' Agreement, and (ii) all ongoing MISO costs, pending the Companies' receipt of a final FERC order approving exit.

As stated in Mr. Beer's testimony, if the KPSC accepts the Companies' exit proposal as described by Mr. Thompson, LG&E and KU would request in this proceeding that the Commission permit the Companies to establish a regulatory asset for the MISO exit fee. The Companies would separately seek authorization in their next base rate case to include in base rates all ongoing (*e.g.*, Schedule 10) MISO-related expenses (as reflected in the test period), as well as all *pro forma* adjustments, pending receipt of final FERC approval to exit MISO. Upon receipt of all necessary final approvals for exit, the Companies would take the requisite ratemaking steps (through a filing with the Commission) to *remove* the MISO-related expenses from base rates, and *begin amortization and base rate recovery* of the regulatory asset over a specific term.

So structured, the above proposal ensures that cost recovery is properly timed to protect against over- or under- recovery at any one point in time (*i.e.*, it prevents the Companies from recovering concurrently exit fee costs and ongoing MISO costs pending receipt of requisite FERC approval).

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 9

Responding Witness: Mathew J. Morey

Q-9. Refer to Exhibit MJM-1, the Cost-Benefit Analysis.

a. Explain in detail how the discount rate of 7 percent was determined. Include all assumptions and supporting calculations.

b. Explain in detail what the line item "Lost Revenues" measures. Include all assumptions and supporting calculations.

A-9. a. The discount rate of 7 percent was used as an approximation of the weighted cost of capital for the combined companies, (i.e., LG&E and KU). The supporting document that is relevant to the choice of this discount rate has been provided in response to Q-9 of the Initial Data Request of the Midwest Independent Transmission System Operator, Inc. The electronic file is named WtdCOCCombinedUtilities.pdf.

b. The line item "Lost Revenues" that appears in Table ES.1 (at p. v of the Cost-Benefit Analysis) is explained in detail in several sections of the Cost-Benefit Analysis. The estimated annual revenues that the Companies would expect to receive from participating as a member of MISO that would be sacrificed (i.e., would become "Lost Revenues") if the Companies withdrew from MISO and operated as a standalone system during the period 2005-2010 have been documented in the Cost-Benefit Analysis. Table 4.1 (at p. 54) presents a breakdown into its component parts of the "Lost Revenues" figures of Table ES.1, and Table 3.3 (which should be numbered 4.3) (at p. 56) describes the assumptions underlying the values appearing in Table 4.1. Section 3.6.1 (at pp. 29-30) describes the component figures that appear in Table 4.1.

There are four categories of these Revenues that would be expected to be sacrificed if the Companies were to withdraw from MISO by the end of 2004 and operate as a standalone system. If the Companies were to remain in

MISO, these revenues would not be sacrificed, and would not be considered "Lost Revenues." First, the Companies expect to receive transmission revenues in the period 2005-2006 that represent partial compensation to LG&E and KU for the elimination of pancaked transmission rates within the MISO footprint and the elimination of through and out rates between MISO and PJM (i.e., inter-regional pancaking). Second, the Companies expect to receive a load-ratio share based allocation of the revenues received by MISO for its sale of excess FTRs. That allocation is expected to average $2.0 million per year. Third, the Companies expect to receive $2.0 million per year as the load-ratio based share of revenues MISO receives for Schedules 1, 2, 7, 8 and 9 and 14.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Com*mission Staff
Dated October 6, 2003

Question No. 10

Responding Witness: Michael S. Beer

Q-10. Assume for purposes of this question that LG&E and KU decide on January 1, 2004 to withdraw from MISO and that there are no significant objections from FERC or MISO to the withdrawal. Provide a time line showing all the events and activities that LG&E and KU would have to undertake to finalize its withdrawal. Based on LG&E and KU's best estimates, include the timing of all required filings with MISO, FERC, and the Securities and Exchange Commission; indicate when final decisions could be expected; and when the withdrawal from MISO would be completed.

A-10. LG&E and KU assume for purposes of this question that the Companies' decision to withdraw from MISO on January 1, 2004, is prompted by an exit directive by the Commission that recognizes the need for and concurs with the conditions described by Mr. Thompson in his testimony. *See* the Companies' response to Question 8. For purposes of this question, the Companies will assume that the Commission issues such order on December 31, 2003.

Within 30 days after receipt of such order from the Commission, the Companies would provide notice of their withdrawal to MISO and all signatories to the MISO Transmission Owners' Agreement (MISO Agreement, Article 7, Part A.3). Similarly, the Companies would be required to seek approval for such withdrawal from the Federal Energy Regulatory Commission ("FERC") under Section 205 of the Federal Power Act ("FPA").[1] (The Companies do not anticipate having to

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[1] That LG&E and KU must obtain FERC approval after receipt of a Commission directive as described above is consistent with Article 7 of the MISO Agreement. The Companies acknowledge that an argument could be made that Article 5 of the MISO Agreement affords LG&E and KU the right to withdraw from MISO absent FERC approval in this instance. In this regard, Article 5, Part I of the MISO Agreement states:

> With regard to these withdrawal rights, the Owner shall remain a Member with all rights and obligations of a Member who is an Owner until such time as the FERC approves the withdrawal, as appropriate. However, no further FERC approval of the withdrawal is required for withdrawals pursuant to ... Article Seven of this Agreement ....*

submit any filings to the Securities and Exchange Commission to effect an exit from MISO.)

For purposes of this question, the Companies assume that there would be little or no opposition to their FPA Section 205 filing (either from FERC, MISO, or other parties). Under FPA Section 205, unless FERC acts on a Section 205 filing within 60 days of the date such filing is made, the filing takes effect by operation of law. In the "no opposition" scenario presented here, FERC would likely issue an order within 60 days of the date of the Companies' filing (*e.g.*, assuming a filing date of January 1, 2004, no later than February 27, 2004), and, under the MISO Agreement, the Companies' withdrawal would take effect on such date. The Companies expect that full withdrawal from MISO could be accomplished, in accordance with the MISO Agreement, after a short transition thereafter.

By contrast, if there were some (even minor) opposition to the filing, the FERC could accept the filing "subject to refund" (*i.e.*, subject to the Companies re-joining MISO) and suspend its effectiveness for up to five months (the limits imposed under the Federal Power Act). At the same time, the FERC would establish hearing procedures to resolve the issues raised. In this scenario, the FERC would issue such suspension order within 60 days of the date of the Companies' filing (*e.g.*, assuming a filing date of January 1, 2004, no later than February 27, 2004), and would establish an "effective date" up to five months thereafter (circa August 2004). Although the Companies believe that this "effective date" would be the proper date used to calculate the Companies' exit fee obligations (*see* the Companies' response to Question 11), the delays inherent in the hearing process render it impossible to determine when a final decision "could be expected; and when the withdrawal from MISO would be completed."

However, the Companies believe that any interpretative ambiguity would be resolved in favor of a FERC approval requirement. Specifically, Article Seven, Part A.3 (that section allowing withdrawal in the wake of state commission action) conspicuously lacks key language contained in other Parts of Article 7, *i.e.*, language that expressly allows members to "withdraw from this Agreement without any additional FERC authorization." *See* MISO Agreement, Article Seven, Parts A.4 and B.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 11

Responding Witness: Michael S. Beer

Q-11. Assuming that LG&E and KU withdraw from MISO, are there differences in the length of notice that must be given prior to withdrawal or the amount of the exit fee based on whether the withdrawal is voluntary or required by a regulatory authority? Explain your response.

A-11. Length of Notice

The MISO Transmission Owners' Agreement does not set forth a specific number of days prior to *voluntary* withdrawal by which a transmission owner must give notice of such withdrawal. Rather, the submission of notice is required to "commence the process of withdrawal of its facilities" from MISO, which cannot become effective "until December 31 of the calendar year following the calendar year in which notice is given . . . ." MISO Agreement, Article 5.I.

By contrast, if withdrawal is required by a regulatory authority, the transmission owner may withdraw "no less than" 30 days after the day of such state regulatory action (effecting a 30-day notice period).

Effective Date of Withdrawal For Exit Fee Purposes

The MISO Transmission Owners' Agreement provides that "[a]ll financial obligations incurred and payments applicable to time period prior to the *effective date of such withdrawal* shall be honored by the withdrawing owner." Article 5.II.B. (Emphasis added.)

Because the Companies must obtain FERC approval of their exit from MISO, the effective date of the Companies' withdrawal for purposes of calculating their exit fee obligation is the later of the (i) exit effective date established by the MISO Agreement, as described above, and (i) the effective date established by FERC in acting on the Companies' application for withdrawal under FPA Section 205.

With regard to voluntary withdrawal, if notice were proffered on January 1, 2004, withdrawal would take effect on December 31, 2005 per the MISO Agreement. Because the Companies assume that by that date, the FERC will already have acted on the Companies' filing as described in the Companies' response to Question 10, the effective date of withdrawal for purposes of calculating the Companies' exit fee would be December 31, 2005, *i.e.*, LG&E and KU would be responsible for all "obligations incurred and payments applicable to time periods" prior to December 31, 2005.

By contrast, if withdrawal is prompted by a KPSC directive, the effective date of exit for purposes of determining the Companies' exit fee obligation would be the later of 30 days after receipt of such directive (per the MISO Agreement) or the date the Companies' FERC filing takes effect. As shown in the Companies' response to Question 10, the latter date will likely occur after such 30-day period. Specifically, assuming the Companies filed their FPA Section 205 application with the FERC on January 1, 2004, the effective date of withdrawal for exit fee purposes could be as late as August 1, 2004. In this scenario, then, LG&E and KU would be responsible for all "obligations incurred and payments applicable to time periods" prior to August 1, 2004.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 12

Responding Witness: Paul W. Thompson

Q-12. Refer to the Thompson Testimony, page 6, lines 9-15. Is it LG&E's and KU's understanding that this Commission's alternative transmission pricing proposal referred to therein related to any issues other than cost-recovery and associated cost allocations of embedded transmission costs? If so, identify all other issues.

A-12. As Mr. Thompson states in his testimony, the only substantive issue with which the Commission appeared to take issue in its comments on MISO's initial filing in 1998 pertained to transmission pricing, *i.e.,* how MISO's transmission rates applicable to bundled loads would be designed after the transition period to avoid perceived cost shifting among customers.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 13

Responding Witness: Mark S. Johnson/Mathew J. Morey

Q-13. Refer to Exhibit MJM-1, the Cost-Benefit Analysis.

a. The original MISO filing at FERC [footnote omitted] provided that during the transition period, rates for the recovery of embedded transmission costs would be based upon zonal costs as opposed to average, MISO system-wide costs, commonly referred to as postage stamp rate. After the transition period, there was a possibility of MISO transmission rates being based on average system costs instead of zonal costs.

(1) What is the current status of MISO's intent or obligation to adopt postage stamp pricing?

(2) The last paragraph on page 34 includes a discussion of zonal vs. postage stamp rates and indicates that no estimate has been developed for the increase in the cost of transmission access if MISO were to adopt postage stamp pricing. Explain why no estimate was developed.

(3) Provide an estimate of the annual effect on revenues and expenses of LG&E and KU of changing from zonal rates to a system-wide postage stamp rate based upon the current MISO configuration and the latest revenue requirements data available.

b. On July 24, 2003, FERC issued an Order in Docket No. RM02-1-000 that permitted "participant funding" for transmission upgrades necessary to accommodate new generation when transmission service is provided by independent transmission providers, but required a crediting approach for non-independent providers. [footnote omitted.] Does the Cost-Benefit Analysis provided as Exhibit MJM-1 reflect the impact of this recent Order?

c. The second to the last paragraph on page viii of the Cost-Benefit Analysis states, in part, "Furthermore, if LGE/KU operated as a standalone system, it could still obtain for its native load customers many of the benefits that accrue to MISO members because it is a first-tier utility vis-à-vis MISO."

(1) What is meant by "first-tier utility"?

(2) Are the benefits referred to here primarily the result of nonpancaked rates? If no, explain what the benefits are and how they can be obtained.

A-13. a.

(1) It is unknown what MISO's intent is with respect to postage stamp pricing. However, MISO and its Transmission Owners have had preliminary discussions regarding transmission pricing alternatives, including the so-called "TRANSLink" pricing approach, and have discussed possible ways to implement that approach in such a way that minimizes cost shifts among MISO members.

(2) As stated in the Cost-Benefit Analysis, the breakeven analysis presents a lower-bound estimate of the net savings over the period 2005 to 2010 that could result from LG&E/KU withdrawing from MISO and operating as a standalone system. Because LG&E/KU's zonal rates are lower than the average zonal rates of other MISO transmission owners, the transition from zonal rates to postage stamp rates would have the effect of increasing the costs of MISO membership. This means that net savings accruing to LG&E/KU from withdrawal at the end of 2004 would be greater than we have estimated for the case without postage stamp rates. We already have shown that the avoided costs of withdrawing outweigh the incremental costs. Any increase in the magnitude of the avoided costs only strengthens the case to be made in favor of withdrawal.

Furthermore, the move from zonal rates to a regional postage stamp rate would not likely occur until late in our analytic period, perhaps in 2008 or later. Thus, the move to a postage stamp rate will not likely have an effect on LG&E/KU's costs of MISO membership until late in the period of time examined in the Cost-Benefit analysis.

(3) The Transmission Owners' Agreement, at Appendix C, Section II.B.1(c) states as follows:

> The Midwest ISO shall file a revision to the rate formula which is set forth in Attachment O to the Transmission Tariff to implement Midwest ISO system-wide transmission rates (i.e., the same transmission rate shall apply to all customers) (i) if all Owners paying the Midwest ISO for transmission service associated with Bundled Load agree; (ii) if all Owners that are paying the Midwest ISO for transmission service associated with Bundled Load are allowed to recover such payments; or (iii) there are no Owners paying the Midwest ISO for transmission service associated with Bundled Load.

It is premature to calculate the effects of a single system wide rate to which all Owners have not agreed. However, LG&E and KU estimate that implementing a single, systemwide rate today would increase the rate the Companies pay for network transmission service by approximately 30 percent. The revenue impact would be *de minimus*.

b. No.

c.

(1) "First-tier utility" refers to a utility whose service territory is partly contiguous with MISO's footprint.

(2) MISO's net short-term efficiency gains (if any) would arise from its offering a lower-cost and/or more reliable commitment and dispatch in the Day 2 Market than can be achieved by each of its members acting separately without MISO's more centralized system operations. Although these efficiency gains would be positive for all MISO members *in the aggregate*, any individual MISO member may be a winner or loser depending upon (i) the LMPs at its resource and load locations; (ii) the distribution of transmission and system operations costs among MISO members; and (iii) the actions of other non-MISO transmission operators on the MISO border.

A company that is located outside of MISO but on MISO's border can partly integrate the commitment and dispatch of its generating units with MISO's regional commitment and dispatch through active bilateral trading with MISO members and through participation in MISO's day-ahead and real-time spot markets. This partial integration can add to the net efficiency gains that are shared among MISO members and, because of the trading, also partly shared by the outside company located on MISO's border.

Like MISO members, the outside company may experience a net gain or a net loss as a result of MISO's administration of the Day 2 Market and the implementation of LMP-based spot pricing. If the company located outside MISO were 100% successful in identifying and consummating all of the cost-reducing day-ahead and real-time trades that would be found by MISO if the company were a MISO member, then, aside from transmission and systems operations costs, the outside company's gains or losses from MISO's creation would identical regardless of whether the company is a MISO member. To the extent that the outside company does not identify all of the cost-reducing day-ahead and real-time trades, the outside company will capture only a portion of the gains or losses.

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00266

Response to First Data Request of Commission Staff
Dated October 6, 2003

Question No. 14

Responding Witness: Mark S. Johnson, Mathew J. Morey

Q-14. On November 6, 2002, LG&E filed responses to the Commission's request for information relating to an informal review of the costs and benefits of RTO membership and FERC's Standard Market Design. In the response to Item No. 13, LG&E and KU estimated their combined exit fee to be paid upon withdrawal from MISO as $9.4 million for capital costs and $2.7 million per year for operating costs applicable to periods prior to withdrawal. Explain the derivation of these amounts and explain why these amounts differ from the $23 million exit fee estimated in the Beer Testimony at page 10.

A-14. Both the exit fee estimated by the Companies in November 2002 in the context of the Commission's informal review of RTO membership and the exit fee estimated by Christensen Associates in the Cost-Benefit Analysis in this proceeding were calculated in accordance with the MISO Transmission Owners' Agreement, which provides that "[a]ll financial obligations incurred and payments applicable to time period prior to the effective date of . . . withdrawal shall be honored by the withdrawing owner." Article 5.II.B. The differences in the estimated exit fee calculated by the Companies and that derived by Christensen Associates are attributable to (i) different estimates of the Companies' share of total member load at the effective date of exit (4.5 percent vs. 5.5 percent); and (ii) different estimates of MISO's capital obligations and operating expenses as of the date of exit ($208 million/$60 million vs. $277 million/$140 million). Both exit fee estimates were based on the assumption that the Companies' withdrawal from MISO would be effective December 31, 2004.

- With regard to the Companies' exit fee estimate in November 2002, the Companies' load ratio share as of December 31, 2004 was estimated to be 4.5%, which percentage was obtained by dividing projected combined Company sales of 45,100 GWh in 2004 by an estimated total MISO member load of approximately one billion MWH. Applying this percentage to MISO's estimated capital and operating expenses as of December 31, 2004 yielded a capital cost burden of approximately $9.4

million (4.5% of an estimated $208.5 million capital cost) and an operating expense burden of $2.7 million (4.5% of $60 million).

- The estimated $23 million exit fee that appears in Mr. Beer's testimony at page 10 was obtained from the Cost-Benefit Analysis conducted by Christensen Associates. A description of how that number was derived can be found in Section 3.13 (at pp. 50-51). The Companies' load ratio share for 2004 was estimated to be 5.5%, which percentage was obtained by dividing projected combined Company sales of 45,100 GWh in 2004 by an estimated total MISO member load of approximately 820 million MWH. Applying this percentage to MISO's estimated capital and operating expenses as of December 31, 2004 yielded a capital cost burden of approximately $15.2 million (5.5% of an estimated $277 million capital cost) and an operating expense burden of $7.7 million (5.5% of $140 million).