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October 26, 2004

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PUBLIC SERVICE COMMISSION

Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 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 Ms. O'Donnell:

Enclosed please find an original and five (5) copies of Louisville Gas and Electric Company's and Kentucky Utilities Company's responses to the Commission Staff's supplemental data requests dated October 13, 2004, in the above-referenced docket.

Should you have any questions concerning the enclosed, please do not hesitate to contact me directly at 502-627-2573.

Sincerely,

Kent W. Blake

Kent W. Blake
Director, Regulatory Initiatives

cc: Parties of Record

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	)	CASE NO. 2003-00266
MIDWEST INDEPENDENT TRANSMISSION	)	
SYSTEM OPERATOR, INC.	)	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY
TO THE COMMISSION STAFF'S
SUPPLEMENTAL DATA REQUESTS
DATED OCTOBER 13, 2004

FILED: OCTOBER 26, 2004

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

CASE NO. 2003-00266

**Response to the Commission Staff's Supplemental Data Requests
Dated October 13, 2004**

Question No. 1

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

Q-1. On page 36 of the U.S. Department of Energy's Transmission Bottleneck Project Report dated March 19, 2003, Midwest Independent Transmission System Operator, Inc. ("MISO") is reported to have indicated that it plans to spend $7 billion in transmission upgrades.

a. Describe the most recent proposal from the Regional Expansion and Criteria Benefits Task Force for allocating the costs of transmission expansions.

b. Under the proposal described above in (a), how much of the costs to upgrade the transmission system would be allocated to LG&E and how much would be allocated to KU?

c. Are these costs of transmission expansions included in any cost/benefit study filed in this proceeding to date? If so, explain how these costs are reflected.

A-1. a. It is important to note that market participants like Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") -- not MISO -- will fund transmission upgrades. The Companies' concern is that MISO will require the Companies' customers to fund transmission upgrades that do not benefit them.

The latest Regional Expansion and Criteria Benefits Task Force ("RECB") proposal is contained in the latest MISO staff versions of OATT Attachments "XX" & "YY," which are attached hereto. Attachment XX "describes the process to be used by the Midwest ISO Planning Staff to develop the Midwest ISO Transmission Expansion Plan ("MTEP"), subject to review and approval by the Board." Attachment XX addresses both reliability upgrades and economic transmission upgrades.

Attachment XX provides that MISO will identify economic transmission upgrades that lower LMP differentials by a predetermined threshold amount. In accordance with Attachment XX MISO will then identify those who benefit from the lowering of LMP differences. If these identified parties fail to come to agreement on cost allocation or are otherwise unwilling to pay for economic upgrades determine prudent by MISO, Attachment XX sets forth alternative dispute resolution procedures binding on those parties MISO had identified as beneficiaries.

b. The MTEP indicates that there are five transmission projects that could provide benefits to the region. These five projects have a total estimated cost of $2.32 billion. It is still not clear how the costs of these projects would be allocated among various market participants and transmission owners in the MISO region should any of these projects be undertaken.

   In response to a question from the Companies at the October 14, 2004 RECB meeting, MISO staff stated that MISO has decided to identify and implement economic upgrades and identify beneficiaries in the manner generally set forth in Attachment XX; however, the particulars of cost allocation among and between identified beneficiaries remain to be worked out. Therefore the Companies have no way to be certain how much their customers ultimately will be asked to pay for transmission projects that may not benefit them.

   The $7 billion in planned transmission investment was a number provided to the Consortium for Electric Reliability Technology Solutions ("CERTS") investigative team prior to MISO's development of the MTEP. In the current MTEP, MISO has studied and determined who is going to build and pay for approximately $1.84 billion in proposed and planned transmission upgrades (as proposed by the transmission owners).[1] Of this amount, $1.32 billion is planned, which means that transmission owners believe these projects should proceed as planned. The remaining amount, $0.52 billion, consists of proposed projects to address perceived reliability problems, but these projects are still under evaluation (or were at the time of the preparation of the MTEP). The MTEP states that KU and LG&E will bear costs of $54 million and $23 million, respectively, through 2007. These amounts include potential upgrades for the addition of Trimble County Unit 2.

c. No. The Companies' cost-benefit analyses assume that the Companies will implement reliability-related transmission upgrades, i.e., those NERC standards require, regardless of their RTO membership, so there will be no cost/benefit differentials between the various cases due to such upgrades. The Companies' analyses did not take into account other kinds of transmission upgrades, as discussed in (b) above, simply because MISO and the other RTOs have yet to finalize the standards they will use to prescribe economic and other kinds of transmission upgrades.

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[1] See Midwest Independent Transmission System Operator, Inc., Midwest ISO Transmission Expansion Plan 2003, Approved by the Midwest ISO Board of Directors June 19, 2003.

ATTACHMENT [XX]

MIDWEST ISO TRANSMISSION EXPANSION PLANNING PROTOCOL

1. **Development Of The Midwest ISO Transmission Expansion Plan - Purpose and Scope:** This Attachment XX describes the process to be used by the Midwest ISO Planning Staff to develop the Midwest ISO Transmission Expansion Plan (MTEP), subject to review and approval by the Board. The provision of this Attachment XX are intended to be applied in a manner that is consistent with the applicable provisions of Appendix B of the Transmission Owners Agreement (TOA).

   a. **Development of the MTEP:** The Planning Staff, working in collaboration with representatives of the Owners and the Planning Advisory Committee, shall develop the MTEP, consistent with Good Utility Practice and taking into consideration long-range planning horizons, as appropriate. The Planning Staff shall develop the MTEP for expected use patterns and analyze the performance of the Transmission System in meeting both reliability needs and the needs of the competitive bulk power market, under a wide variety of contingency conditions. The MTEP will give full consideration to the needs of all Market Participants, will include consideration of demand-side options, and will identify expansions or enhancements needed to support competition in bulk power markets and in maintaining reliability. This analysis and planning process shall integrate into the development of the MTEP among other things: (i) the transmission needs identified from Facilities Studies carried out in connection with specific transmission service requests; (ii) transmission needs associated with generator interconnection service; (iii) the transmission needs identified by the Owners in connection with their planning analyses to provide reliable power supply to their connected load customers and to expand trading opportunities, better integrate the grid and alleviate congestion; (iv) the transmission planning obligations of an Owner, imposed by federal or state law(s) or regulatory authorities, which can no longer be performed solely by the Owner following transfer of functional control of its transmission facilities to the Midwest ISO; (v) plans and analyses developed by the Planning Staff to provide for a reliable Transmission System and to expand trading opportunities, better integrate the grid and alleviate congestion; (vi) the inputs provided by the Planning Advisory Committee; and (vii) the inputs, if any, provided by the state regulatory authorities having jurisdiction over any of the Owners and by the OMS.

b. **Project Coordination:** In the course of this process, the Planning Staff shall seek out opportunities to coordinate or consolidate, where possible, individually defined transmission projects into more comprehensive cost-effective developments subject to the limitations imposed by prior commitments and lead time constraints. This multi-party collaborative process is designed to ensure the development of the most efficient and cost-effective MTEP that will meet reliability needs and expand trading opportunities, better integrate the grid, and alleviate congestion, while giving consideration to the inputs from all stakeholders.

2. **Development of Reliability Upgrade Projects:** Reliability Upgrade Projects are defined for purposes of this Attachment XX as projects that are required to ensure that the Transmission System is in compliance with applicable reliability requirements of NERC, regional reliability councils, or successor organizations, Owners' planning criteria filed with federal, state, or local regulatory authorities, and applicable federal, state and local system planning and operating reliability criteria. Reliability Upgrade Projects include projects that are needed to maintain reliability while accommodating the ongoing needs of existing transmission customers, as well as the incremental needs associated with requests for new transmission or interconnection service, as determined in Facilities Studies associated with such requests. The Planning Staff shall test the MTEP for adequacy and security based on all applicable criteria, and shall produce a Baseline Reliability Plan that includes all Reliability Upgrade Projects determined by the Planning Staff to be necessary through the planning horizon of the MTEP. All Reliability Upgrade

Projects proposed for inclusion in the MTEP shall be subject to Board approval, as set forth in Section 6.

3. **Development of Economic Upgrade Projects:** Economic Upgrade Projects are defined for purposes of this Attachment XX as projects that are required to support competition in bulk power markets by expanding trading opportunities or alleviating congestion, or that otherwise provide sufficient benefits to justify inclusion in the MTEP but which are not required to meet reliability criteria applicable within the Midwest ISO, or that is proposed to meet an identified reliability need, but that has a greater project direct cost than one or more alternative Reliability Upgrade Projects identified in the development of the MTEP that would alternatively resolve reliability needs through the MTEP reliability evaluation planning horizon. After the Planning Staff has initially drafted the Baseline Reliability Plan, the Midwest ISO, Transmission Owners, ITC's, Market Participants, or regulatory authorities may propose to include Economic Upgrade Projects in the MTEP. Such proposals may be made by the Midwest ISO, Transmission Owners or ITC's, or other registered Market Participants, or by regulatory authorities. All Economic Upgrade Projects proposed for inclusion in the MTEP shall be subject to Board approval, as set forth in Section 6.

Deleted: ~~are not the least cost[1] alternative to meet such reliability criteria. A project that is proposed to meet an identified reliability need, but that has a greater project cost than one or more alternative projects may be evaluated for economic benefits, subject to the threshold evaluation criteria of Section 3.a.~~

   a. **Threshold Criteria for Economic Upgrade Projects:** The Planning Staff will apply threshold criteria for determining which proposed Economic Upgrade Projects to evaluate for inclusion in the MTEP, and also to determine whether an evaluated project has sufficient expected benefits relative to project cost to be included in the MTEP. The results of such evaluation will be used to determine whether a proposed Economic Upgrade Project qualifies for inclusion in the MTEP. A project that does not so qualify is not precluded from being proposed for consideration under other applicable provisions of the Tariff.

i. **Threshold Evaluation Criteria:**

i. **Projects at 200kV and Above.** All proposed projects of 200 kV and above will be evaluated for economic benefits, as set forth in Section 3.a.ii.

ii. **Projects at Voltage Levels Between 100kV and 200kV.** Unless the Planning Staff determines that a project with voltages between 100 kV and 200 kV will be assessed for economic benefits, such a project will only be evaluated for economic benefits if the entity proposing the project provides a preliminary analysis demonstrating potential economic benefits pursuant to Section 3.a.ii, or demonstrating that the project will relieve congestion on a facility(ies) known to cause significant congestion.

iii. **Projects at Voltages 100kV and Below.** Unless the Planning Staff determines that a project with voltages of 100 kV and below will be assessed for economic benefits, such a project will only be evaluated for economic benefits if it has been justified based on the analysis set forth in Section 3.a.i(b) above, and the request is supported by two or more of the following entities: Midwest ISO members; Midwest ISO registered Market Participants; Midwest ISO regulatory authorities; or, adjacent RTOs.

ii. **Threshold Inclusion Criteria:** Economic Upgrade Projects that satisfy the Threshold Evaluation Criteria in Section 3.a.i will be further evaluated based on their net economic benefits to determine whether they will be included in the MTEP. Such inclusion evaluation will determine whether the net present value ("NPV") of economic benefits of a project is expected to exceed the NPV of revenue requirements for the project, as further set forth in Section 3.b. .

b. **Calculation of Net Economic Benefits of Economic Upgrade Projects:**

i. Calculation of Annual Economic Benefits: The annual economic benefits of an Economic Upgrade Project will be measured based, at a minimum, on the change in projected production cost of all registered Midwest ISO Generation Resources and other resources with executed Interconnection Agreements with the Midwest ISO, adjusted for changes in purchases and sales to non Market Participants, arising as a result of the expansion proposal. The adjustment for changes in sales to non-Market Participants by generation included in the production cost calculation will, to the extent practicable, exclude from calculated annual economic benefits the changes in sales made by generators that are not affiliated with bundled retail load served within the Midwest ISO. The production cost calculations will also include a variety of sensitivity cases reflecting interconnection of various Generation Resources without executed Interconnection Agreements but that are active in the Midwest ISO interconnection queue, as well as sensitivities to the possible retirement of various resources. Sensitivities to addition of generation that is not in the interconnection queue may also be performed as needed to reflect a reasonable load-generation balance within the Midwest ISO market. The production cost savings will be determined through a series of model simulations using PROMOD, or an equivalent hourly chronological market assessment tool, to determine the difference between a) the annual production cost for the base case without the proposed project and b) the annual production cost for the change case with the proposed project incorporated. The production cost analysis will reflect the security constrained economic dispatch of generating units located within MISO and applicable surrounding systems. The production costs will be determined based on the fuel and variable operating costs of each generating unit estimated from available forecasts and data. The hourly production costs will be summed over all hours of the year for all generating units to develop the total annual production costs. The difference in the production costs between the base case and the case with the facility incorporated will reflect annual operational savings solely attributed to the addition of the transmission upgrade facility. The calculation of net economic benefits of an Economic Upgrade Project will not place a monetary value on reliability benefits unless and until a methodology for such valuation is developed and included in the Midwest ISO business practices.

ii. **Calculation of Net Present Value of Economic Benefits**: The annual economic benefits of an Economic Upgrade Project will be estimated for each year through a period of ten (10) years from the proposed in-service year. The present value of the levelized annual fixed charges associated with the revenue requirements for the project will be determined using the discount rate applicable to the funding entity and over the depreciation life for transmission projects applicable to the funding entity. The same discount rate will be used to determine the present value of the annual economic benefits. The annual economic benefits for the present value calculations generally will be determined by evaluating three separate years for each project: the service date year, the MTEP case year (typically a five year horizon case), and the tenth (10^{th}) year forward from the proposed in-service year. Other years may be evaluated if deemed critical based on significant expected system changes expected to occur in particular years of the planning horizon that in the opinion of the Midwest ISO could significantly impact the benefits calculation. Annual economic benefits will be estimated for intermediate years as a linear scale between each of the three measurement years. For years beyond the MTEP horizon year needed to extend the analysis to the tenth year planning horizon, system loads will be scaled based on LSE forecasts of load growth, and generation additions will be based on generation entries in the interconnection queue, to the extent practicable.

An end of the year calculation will determine the total present value of the production cost savings. An example of the calculation of present value of annual economic benefits is shown below for a discount rate of 10%.

Study Year	Delta Prod. Costs[1]	Discount Factor	PV
1	$10,242,000	1.00	10,242,000
2	$10,446,840	0.91	10,446,840
3	$10,655,777	0.83	9,687,070
4	$5,327,888	0.75	4,403,214
5	$5,434,446	0.68	4,082,980
6	$5,543,135	0.62	3,786,036
7	$5,653,998	0.56	3,510,688
8	$5,767,078	0.51	3,255,365
9	$5,882,419	0.47	3,018,611
10	$2,941,210	0.42	1,372,096
Total			$53,804,899

1. Annual production cost reduction adjusted for changes in non-market purchases and sales.

c. **Inclusion Criteria for Economic Upgrade Projects**: To qualify as an Economic Upgrade Project to be included in the regional plan (MTEP), the project must show a present value of economic benefits greater than the present value of project revenue requirements.

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Deleted: ; and (ii) the Market Test must show that the benefits estimate is consistent with reliance on regulated transmission investment because the present value of market revenues from the incremental CFTRs associated with the project are less than the present value of project revenue requirements.

d. **Evaluation of Multiple Proposed Economic Upgrade Projects:** After the Baseline Reliability Plan is developed, if there are multiple proposed Economic Upgrade Projects, such projects will be added to the models one at a time and the incremental economic benefit of each such project measured for the MTEP planning horizon year, or other appropriate year, and compared to an estimate of the levelized annual revenue requirement for the project. The proposed Economic Upgrade Projects will be successively added to the model in order of greatest individual economic benefit net of the levelized annual revenue requirement, and the full net economic benefit of the project will be calculated as per Section 3.b. The economic benefit of each project will be evaluated in this manner before proceeding to the next project. As each project is analyzed, any project that fails the Section 3.a.ii criteria will be removed from the sequence.

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4. **Designation of Cost Responsibility for MTEP Projects.**

a. **Initial Designation of Cost Responsibility for MTEP Projects:** Based on the planning analysis performed by the Planning Staff, which shall take into consideration all appropriate input from participants, including, but not limited to, any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended MTEP shall, for any enhancement or expansion that is included in the plan, designate: (i) the Market Participant(s) in one or more Zones that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any applicable provision of the Tariff, including Attachments N, R, X, or any applicable cost allocation method ordered by the FERC; or, (ii) in the event and to the extent that no provision of the Tariff so assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancements or expansions shall be recovered through charges established pursuant to Attachment YY to the Tariff. Any designation under clause (ii) of the preceding sentence or under Section D of Attachment N shall be based on the Planning Staff's assessment of, as established in the Expansion Planning Business Practices of the Midwest ISO, the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, shall be subject to the provisions of Section 4.b and to FERC review and approval, and shall be incorporated in any amendment to Attachment YY of the Tariff that establishes a Network Upgrade Charge Rate in connection with an expansion or enhancement included in the MTEP.

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b. **Resolution of Cost Responsibility for MTEP Projects:**

i. Based on the Planning Staff's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion, the Planning Staff will designate entities as

"Designated Responsible Parties," which designation may include some or all of the entities proposing the MTEP project. The Designated Responsible Parties for an MTEP project will be given a 60-day period to work together to reach voluntary agreement on cost allocation percentages and procedures for project development within a specified time frame.

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ii. The Midwest ISO and the Designated Responsible Parties (collectively, "parties") will be given a 60-day period to conduct negotiations to reach voluntary agreement on cost allocation percentages and procedures for MTEP project development. The parties will contact the FERC Dispute Resolution Service ("DRS") for assistance with a facilitative process for any MTEP cost allocation negotiations during this 60-day period.

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iii. If the Designated Responsible Parties are unable to reach voluntary agreement on cost allocation percentages and procedures for an MTEP Project within the 60-day negotiation time period,, the Midwest ISO and the Designated Responsible Parties will submit the dispute to binding arbitration pursuant to the process and procedures detailed in Section 4.c and 4.d, as well as pursuant to the Commission regulations contained in 18 C.F.R. Sections 385.604 and 385.605.

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c. **Binding Arbitration Process:**

i. Any disputes regarding the allocation of costs for Reliability Upgrade Projects and/or for Economic Upgrade Projects that are unable to be resolved in the 60-day negotiation time period will be submitted to DRS for implementation of the following binding arbitration process. The arbitration process herein shall be limited in scope to resolution of the allocation of cost responsibilities for the subject projects, and

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parties shall not be permitted to dispute the need for the projects or information, data, or analyses upon which the need for the projects was determined, except as such information, data, or analyses was also applied to the determination of cost responsibility for the projects.

ii. The Midwest ISO will promptly notify DRS in writing of the need for a binding arbitration proceeding, and DRS will contact all affected parties and/or any parties in interest to this dispute, and will prepare any necessary notices.

iii. Within 5 days of being contacted by the parties regarding binding arbitration, the DRS will assist the parties in selecting an appropriate third-party neutral or FERC Administrative Law Judge (hereinafter referred to as "Arbitrator") who is mutually agreeable to the parties. Any Arbitrator selected by mutual choice of the parties, shall be subject to disqualification only in circumstances likely to affect impartiality or independence, including any bias or any financial or personal interest in the result of the arbitration or any past or present relationship with the parties or representatives. If the parties specifically agree in writing, the Arbitrator shall not be subject to disqualification. If the parties are unable to agree on the Arbitrator, then DRS as an independent entity will chose a replacement Arbitrator at its sole discretion; or DRS could assist in an elimination process whereby an Arbitrator is chosen by default.

iv. Once an Arbitrator has been agreed to by the parties, a binding arbitration proceeding under Section 4 will be convened and completed within a time period to be mutually agreed to by the parties but in no circumstances will the binding arbitration process exceed 180 days.

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v. The Arbitrator will convene the parties at a mutually agreeable location at a mutually agreeable time for the binding arbitration hearing. The parties shall respond to the Arbitrator's requests for hearing dates in a prompt manner and be cooperative in scheduling the earliest practicable date.

vi. The parties shall not communicate unilaterally concerning the arbitration with the Arbitrator, unless the parties agree otherwise or the Arbitrator so directs. The Arbitrator for good cause shown may postpone any arbitration hearing upon agreement of the parties, upon request of a party, or upon the Arbitrator's own initiative.

vii. The Arbitrator may regulate the course of and conduct of the arbitral hearings; administer oaths and affirmations; compel attendance of witnesses and the production of evidence to the extent the Commission is authorized by law to do so. A stenographic recording shall be provided for each arbitration hearing and the parties to the particular hearing shall pay the costs of the record. The Arbitrator may determine the stenographic record to be the official record of the arbitration proceeding, provided that it is made available to the parties for inspection.

viii. The parties shall present evidence supporting or opposing the MTEP cost allocation percentages and procedures. Witnesses for each party shall also submit to questions from the Arbitrator and the adverse party. The Arbitrator may receive any oral or documentary evidence, except that irrelevant, immaterial, unduly repetitious, or privileged evidence may be excluded by the Arbitrator. The Arbitrator, with the consent of parties, may conduct all or part of the arbitration hearing by telephone, television, computer, or other electronic means, as long as each party has the opportunity to take part in the arbitration proceeding. The Arbitrator has discretion to vary this procedure, provided that the parties are treated equally and that each party has the right to be heard and is given a fair opportunity to present evidence.

ix. When satisfied that the presentation of the parties is complete, the Arbitrator shall declare the hearing closed. If documents or briefs are to be filed, the arbitration hearing shall be declared closed as the final date set by the arbitrator for the receipt of such documents or briefs. The Arbitrator will be required to render the arbitration award within 15 days after the close of the hearing.

x. The arbitration award shall be in writing and signed by the Arbitrator. The Arbitrator shall provide in the body of the arbitration award a concise explanation and breakdown regarding the MTEP percentages and amounts as applied to the parties, including all relevant discussions regarding the appropriate MTEP procedures and related factual determinations.

d. **Results of Binding Arbitration Process:** The Midwest ISO must file the arbitration award with the Commission, along with proof of service on all interested parties, within 5 days of issuance. The arbitration award will become final and binding 30-days after it has been served on all parties. The arbitration award will become a final and binding schedule under the Tariff upon approval by the Commission. It is the parties intent that the Commission afford substantial deference to the Arbitrator's final arbitration award. The parties may only appeal such a binding arbitration award on the grounds that the conduct of the Arbitrator, or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. Specifically, the standards are: (1) where the arbitration award is contrary to public policy; (2) the award is arbitrary and capricious; (3) where the rights of the parties have been prejudiced; (4) where the arbitration award was procured by corruption, fraud, or undue means; (5) where there was evident partiality or corruption in the Arbitrators; and (6) where the Arbitrator is guilty of misconduct and/or exceeded his powers. Since the Commission's stated goal of binding arbitration for parties is to avoid time-consuming and expensive administrative proceedings, the parties may not re-litigate the MTEP cost allocation issues decided by the Arbitrator in the final arbitration award.

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5. **Designation of Entities to Construct, Own and/or Finance MTEP Projects:** For each project included in the recommended MTEP, the plan shall designate, based on the planning analysis performed by the Planning Staff; other input from participants, including, but not limited to, any indications of a willingness to bear cost responsibility for the project; and applicable provisions of the TOA, one or more Transmission Owners or other entities to construct, own and/or finance the recommended project.

6. **Implementation of the MTEP:**

   a. Except as set forth in Section 4, if the Planning Staff and any Owner's planning representatives, or other designated entity(ies), cannot reach agreement on any element of the MTEP, the dispute may be resolved through the Dispute Resolution process provided in the Tariff, or by the FERC or state regulatory authorities, where appropriate. The MTEP shall have as one of its goals the satisfaction of all regulatory requirements as specified in Appendix B or Article IV, Section I, Paragraph C of the Transmission Owner's Agreement.

   b. The Planning Staff shall present the MTEP, along with a summary of relevant alternative projects that were not selected, to the Board for approval on a biennial basis, or more frequently if needed. The proposed MTEP shall include specific projects already approved as a result of the Midwest ISO entering into service agreements with transmission customers where such agreements provide for identification of needed transmission construction, timetable, cost, and Owner or other parties' construction responsibilities.

   c. Approval of the MTEP by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities. The Midwest ISO shall provide a copy of the MTEP to all applicable federal and state regulatory authorities. The affected Owner(s), or other designated entity(ies), shall make a good faith effort to design, certify, and build the designated facilities to fulfill the approved MTEP. However, in the event that a proposed project is being challenged through the Dispute Resolution process under the Tariff, the obligation of the Owners, or other designated entity(ies), to build that specific project (subject to required approvals) is waived until the project emerges from the Dispute Resolution process as an approved project. The Board shall allow the Owners, or other designated entity(ies), to optimize the final design of specific facilities and their in-service dates if necessary to accommodate changing conditions, provided that such changes comport with the approved MTEP and provided that any such changes are accepted by the Midwest ISO. Any disagreements concerning such matters shall be subject to the Dispute Resolution process of the Tariff.

d. The Planning Staff shall assist the affected Owner(s), or other designated entity(ies), in justifying the need for, and obtaining certification of, any facilities required by the approved MTEP by preparing and presenting testimony in any proceedings before state or federal courts, regulatory authorities, or other agencies as may be required. The Midwest ISO shall publish annually, and distribute to all Members and all appropriate state regulatory authorities, a five-to-ten-year planning report of forecasted transmission requirements. Annual reports and planning reports shall be available to the general public upon request.

ATTACHMENT YY

MISO NETWORK UPGRADE COST ALLOCATION

(a) The Midwest ISO Transmission Expansion Plan ("MTEP"), periodically developed pursuant to Appendix B of the Transmission Owners Agreement and Attachment XX from time to time, may designate one or more Transmission Owner to construct and own or finance Network Upgrades. A Transmission Owner, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Network Upgrades on a multi-Pricing Zone basis rather than from customers solely within its Pricing Zone. Other infrastructure improvements that do not warrant regional compensation (local upgrades) shall continue to be compensated by rates in the respective Pricing Zones.

(b) In recognition that the benefits from regional energy markets, system reliability and operational performance of Network Upgrades accrue to many Market Participants, the Transmission Provider shall make reasonable efforts to ensure that Transmission Customers that benefit from Network Upgrades pay for them in Pricing Zone rates.

(c) The Transmission Provider shall identity in this Attachment YY the Network Upgrades that shall be apportioned to two or more Pricing Zones. Such designations shall be the same as those made for the relevant Network Upgrades in the MTEP.

(d) Network Upgrades that are apportioned to each Pricing Zone shall be compensated by the formulary rates contained in Attachment O.

(e) Subject to agreement between or among the affected Pricing Zones, or subject to the dispute resolution procedures contained in Section 4 of Attachment XX, to the extent that one Transmission Owner completes a Network Upgrade that benefits Transmission Customers in one or more additional Pricing Zones, a regulatory asset will be created for each affected Pricing Zone that is equivalent to its share of the benefits of the Network Upgrade. The regulatory asset will become (new) Line 29a on Page 2 of Attachment O. Such regulatory asset will be subject to the average depreciation rate of the Pricing Zone's other transmission plant. To the extent that adjacent Transmission Owners construct and own portions of a Network Upgrade, the regulatory asset methodology described herein shall allocate the costs to match the benefits to the extent practicable.

(f) Nothing contained in this Attachment YY shall limit the right of a Transmission Owner under Section 205 of the Federal Power Act and consistent with the Transmission Owner's Agreement to file with the Commission individually and unilaterally to recover the cost of a Network Upgrade in a manner other than that specified in this Attachment YY, including, but not limited to recover rate incentives not specified herein and to recover the cost of Network Upgrades through its Pricing Zone rates under Schedules 7, 8, and 9.

ATTACHMENT YY

MISO NETWORK UPGRADE CHARGE

1. Determination of MISO Network Upgrade Charge ("NUC"):

(a) The Midwest ISO Transmission Expansion Plan ("MTEP"), periodically developed pursuant to Appendix B of the Transmission Owners Agreement and Attachment XX from time to time, may designate one or more Transmission Owner and/or transmission company (hereinafter "Midwest ISO Entity") to construct and own or finance Network Upgrades. A Midwest ISO Entity, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Network Upgrades on a regional basis rather than from customers within its Pricing Zone. The Transmission Provider will seek to collect on behalf of such Midwest ISO Entity a charge to recover the costs of Network Upgrades. Other infrastructure improvements that do not warrant regional compensation ("Local Upgrades") shall continue to be compensated by rates in the respective Pricing Zones.

(b) The MISO Network Upgrade Charge shall be established in this Attachment YY. In recognition that the benefits from regional energy markets, system reliability and operational performance of Network Upgrades accrue to regional Market Participants, the Transmission Provider shall ensure that all its Transmission Customers are subject to the NUC, which shall be Schedule __ to the Tariff.

(c) The Transmission Provider shall identity in this Attachment YY the Network Upgrades that form the basis of the NUC. Such designations shall be the same as those made for the relevant Network Upgrades in the MTEP. By March 31 of each year, each MISO Entity shall furnish to the Transmission Provider: (1) its gross plant investment in Network Upgrades as of December 31 of the previous calendar year; (2) its Fixed Charge Rate, as described below; and (3) its twelve monthly transmission system peaks. The annual revenue requirement for each MISO Entity shall be the product of its end of year transmission investment and its Fixed Charge Rate. The NUC annual revenue requirement shall be the sum of all MISO Entities annual revenue requirements. The Transmission Provider shall develop monthly, weekly, daily, and hourly transmission charges in accordance with the *AEP* method.

(d) Regional Transmission Customers shall pay the Transmission Provider the current NUC in addition to all other charges for transmission service for which such customers are responsible under the Tariff. As and to the extent that the Transmission Provider collects revenues from Transmission Customers under the NUC pursuant to this Attachment YY, it shall remit or credit such revenues to the MISO Entities in proportion to their annual NUC revenue requirement. An example of this calculation is appended to this Attachment YY as Exhibit 1.

2. Calculation of the Network Upgrade Charge:

(a) The Fixed Carrying Charge shall be the sum of five cost of service elements as found in Attachment O of each Midwest ISO Entity: (1) Operation and Maintenance Expense; (2) Depreciation Expense; (3) Other Taxes; (4) Return; and (5) Income Taxes.

(b) The Operation and Maintenance component of the Fixed Carrying Charge shall be Attachment O, Page 3, Line 8, Column 5, divided by Gross Plant in Service (Attachment O, Page 2, Line 6, Column 5).

(c) The Depreciation Expense component of the Fixed Carrying Charge shall be the amount of depreciation calculated by the sinking fund method (described below) divided by Gross Plant in Service (Attachment O, Page 2, Line 6, Column 5).

$$\text{Sinking Fund Amount} = \frac{\text{Allowed Return}}{(((1 + \text{Allowed Return})^{\wedge}\text{Depreciable Life}) - 1)}$$

Where: Allowed Return is found at Attachment O, Page 4, Line 30, and Depreciable Life is the number of years calculated by dividing Gross Plant in Service (Attachment O, Page 2, Line 6, Column 5) by the Depreciation Expense found at Attachment O, Page 3, Line 12, Column 5.

(d) the Other Taxes component of the Fixed Carrying Charge is Attachment O, Page 3, Line 20, Column 5 divided by Gross Plant In Service (Attachment O, Page 2, Line 6, Column 5).

(e) The Return component of the Fixed Carrying Charge shall be Attachment O, Page 4, Line 30 (last column).

(f) The Income Tax component of the Fixed Carrying Charge shall be the composite income tax rate (described below) times the Allowed Return (Attachment O, Page 4, Line 30), divided by one minus the composite tax rate. The composite tax rate is equal to the statutory Federal corporate Income Tax rate (currently 35%) plus one minus the state income tax rate (if any) times the state income tax rate (if any).

(g) An example of the components of the Fixed Carrying Charge is appended to this Attachment YY as Exhibit 2.

(h) Nothing contained in this Attachment YY shall limit the right of a Transmission Owner under Section 205 of the Federal Power Act and consistent with the Transmission Owner's Agreement to file with the Commission individually and unilaterally to recover the cost of a Network Upgrade in a manner other than that specified in this Attachment YY, including, but not limited to recover rate incentives not specified herein and to recover the cost of Network Upgrades through its Pricing Zone rates under Schedules 7, 8, and 9.

UTILITY A'S FIXED CARRYING CHARGE ANALYSIS

Yellow fields are for inputs

		Utility A
Gross Investment =		$ -
Annual Levelized Payment =		$ -

Summary		
O&M		2.120%
Depreciation Expense	*sinking fund method*	1.042%
Other Taxes		0.000%
Return		9.834%
Income Taxes		3.109%
Total:		**16.105%**

Capitalization:	Amount	Percent	Cost	Weighted Cost
Long Term Debt	$ 242,266,300	65%	8.0%	5.20%
Preferred Stock	$ -	0%	0.0%	0.00%
Common Equity	$ 130,639,522	36%	12.88%	4.64%
				9.83%

Other Taxes:	
Payroll	
Highway & Vehicle	
Property	
Gross Receipts	
Payments in Lieu	
Other	
Total:	$ -

Straight Line Rate:		4.00%
Depreciable Life:		25
Sinking Fund Depr'n		**1.042%**
FIT Rate:	35.0%	
SIT Rate:	7.9%	
Composite Rate wTEP:	40.1%	
Inc Tax Component:		**3.109%**

UTILITY B'S FIXED CARRYING CHARGE ANALYSIS

Yellow fields are for inputs

	Utility B
Gross Investment =	$ -
Annual Levelized Payment =	$ -

Summary		
O&M		3.000%
Depreciation Expense	*sinking fund method*	1.002%
Other Taxes		0.000%
Return		10.100%
Income Taxes		3.285%
Total:		**17.386%**

Capitalization:	Amount	Percent	Cost	Weighted Cost
Long Term Debt	$ 266,717,005	50%	8.0%	4.00%
Preferred Stock	$ -	0%	0.0%	0.00%
Common Equity	$ 266,717,005	50%	12.2%	6.10%
				10.10%

Other Taxes:	
Payroll	
Highway & Vehicle	
Property	
Gross Receipts	
Payments in Lieu	
Other	
Total:	$ -

Straight Line Rate:	4.00%
Depreciable Life:	25
Sinking Fund Depr'n	**1.002%**

FIT Rate:	35.0%	
SIT Rate:	0.0%	
Composite Rate wTEP:	35.0%	
Inc Tax Component:		**3.285%**

SCHEDULE 9-A NETWORK UPGRADE CHARGE (NUC)

Calendar Year 2012

A	B Gross NUC Plant	C Fixed Charge Rate	D Annual Revenue Requirement	E Coincident Kilowatts		Revenue Distribution
Utility A	$ 97,150,639	16.11%	$ 15,646,110	8,266,942		13.360%
Utility B	$ 22,947,368	17.39%	$ 3,989,629	4,429,367		3.407%
Utility C	$ 52,936,422	17.43%	$ 9,226,818	3,596,344		7.879%
Utility D	$ 97,263,200	14.89%	$ 14,482,490	6,297,236		12.366%
Utility E	$ 37,899,362	13.96%	$ 5,290,751	1,873,694		4.518%
Utility F	$ 8,989,206	16.34%	$ 1,468,836	897,266		1.254%
Utility G	$ 84,934,622	15.63%	$ 13,275,281	7,593,600		11.336%
Utility H	$ 55,967,321	14.89%	$ 8,333,534	4,293,468		7.116%
Utility I	$ 54,239,782	16.95%	$ 9,193,643	9,703,691		7.850%
Utility J	$ 9,233,699	14.02%	$ 1,294,565	2,973,036		1.105%
Utility K	$ 44,975,369	13.66%	$ 6,143,635	6,935,872		5.246%
Utility L	$ 3,697,266	14.09%	$ 520,945	2,169,325		0.445%
Utility M	$ 18,976,334	15.67%	$ 2,973,592	5,250,690		2.539%
Utility N	$ 65,302,500	16.23%	$ 10,598,596	9,875,322		9.050%
Utility O	$ 22,899,634	14.59%	$ 3,341,057	3,694,023		2.853%
Utility P	$ 66,975,866	16.92%	$ 11,332,317	2,693,422		9.676%
	$ 744,388,590		$ 117,111,800	80,543,298	**$1.45 per kW/mo**	100.000%

Fixed Charge Rate uses Sinking Fund Depreciation as applied to Gross Transmission Plant
Revenue distribution would be prorated according to the revenue requirement in Column D

UTILITY C'S FIXED CARRYING CHARGE ANALYSIS

Yellow fields are for inputs

				Utility C
Gross Investment =				$ -
Annual Levelized Payment =				$ -

Summary		
O&M		2.550%
Depreciation Expense	*sinking fund method*	1.002%
Other Taxes		0.000%
Return		10.100%
Income Taxes		3.779%
Total:		**17.430%**

Capitalization:	Amount	Percent	Cost	Weighted Cost
Long Term Debt	$ 266,717,005	50%	8.0%	4.00%
Preferred Stock	$ -	0%	0.0%	0.00%
Common Equity	$ 266,717,005	50%	12.2%	6.10%
				10.10%

Other Taxes:	
Payroll	
Highway & Vehicle	
Property	
Gross Receipts	
Payments in Lieu	
Other	
Total:	$ -

Straight Line Rate:		4.00%
Depreciable Life:		25
Sinking Fund Depr'n		**1.002%**
FIT Rate:	35.0%	
SIT Rate:	5.0%	
Composite Rate wTEP:	38.3%	
Inc Tax Component:		**3.779%**

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Question No. 2

Responding Witness: Mark S. Johnson

Q-2. In Docket No. EL02-111 at the Federal Energy Regulatory Commission, two competing proposals were filed on October 1, 2004 for long-term transmission pricing structures. Provide a summary of each proposal and an estimated cost impact of each proposal on LG&E and KU.

A-2. The two proposals filed were the Regional Pricing Proposal (RPP) and the Unified Plan Proponents (UPP). The RPP was supported by Kentucky Transmission Owners LG&E/KU and AEP along with Exelon Corp., Ameren Services Corp. and Allegheny Power. Together theses companies own 55% of the high voltage facilities located in the Midwest ISO and the PJM super-region. The UPP is supported by Kentucky Transmission Owner CINERGY and 25 others located in the MISO and PJM RTOs.

Regional Pricing Proposal

The RPP allocates cost among all load located with MISO and PJM by using two methods each weighted equally, Usage Based Allocation Method and Reliability Based Allocation Method.

Usage Based Allocation Method

This part is intended to "1) reflect usage of the grid, 2) be forward looking, 3) be consistent with market operations, 4) encourage appropriate expansion, 5) provide flexibility, and 6) meet FERC's objects as set forth in Order Nos. 888 and 2000."[2]

The GE MAPS flow based model is used to measure the amount of the regional transmission grid used for power transfers from one zone to another zone. The base case assumed each zone was self-sufficient and the change case assumed an efficient market where all generating facilities are economically dispatched to serve all load within the region. The difference in grid usage between the base

[2] Midwest Independent Transmission System Operator, Inc., FERC Docket No. EL02-111, Regional Transmission Rate Proposal for MISO and PJM in Compliance with the Going-Forward Principles and Procedures (10/1/04) at 13.

and change cases identifies the portion of the transmission owner's costs that should be collected through a region-wide charge. The charge is allocated to zonal load based on the net import allocator derived from the usage-based model. Under this method if a generator locates in Kentucky on the LG&E/KU, CINERGY or AEP transmission systems to serve load outside of Kentucky, then the non-Kentucky load would be allocated a portion of the existing costs of the Kentucky transmission facilities.

Reliability Allocation Method

This method is designed to capture the reliability enhancements that higher voltage transmission facilities provide to the grid. This method is commonly called a "highway-byway" design, because it classifies certain higher-voltage transmission facilities as "highways" and the remainder as "byways." The costs of the "highways," which provide reliability and capability benefits, are aggregated into a regional transmission rate and allocated to load throughout the region using a postage stamp rate design, i.e., all load pays the same rate.

For the sake of equity, there are two highway-byway investment definition schemes, one for transmission owners who own facilities of over 200 kV and another for those who own facilities under 200 kV only. For the first group, 100% of investment in transmission facilities a utility operates above 700kV qualifies as "highway" investment. In addition, 100% of the largest investment class of facilities a utility operates between 200kV and 700kV and 50% of the second largest investment class of facilities a utility operates between 200kV and 700kV also qualify as "highway" investment. For the second group, 50% of a utility's investment in its highest voltage classification facilities over 100 kV qualifies.

A transmission owner's net highway facility investment divided by the transmission owner's total net transmission facility investment produces a percentage used to allocate a portion of the transmission owner's revenue requirement to the regional transmission rate.

As proposed, this plan will have an additional $13 million positive impact on the Companies' revenue per year.

Unified Pricing Proponents (UPP)

Many of the remaining transmission owners in the MISO/PJM super-region propose an alternative approach to the long-term pricing issue. They generally support the continuation of the current zonal pricing regime. Their rationale is that transmission owners built facilities to serve their native load and native load has "agreed" to pay for these facilities, so none of the costs of the high-voltage facilities should be allocated to customers in other zones. Still, the concept of mutual contribution of facilities is the cornerstone of the UPP. The argument is based on the notion that one set of transmission facilities cannot be valued more or less highly than another by virtue of the network characteristics of the grid.

The UPP proposal takes an approach different to future transmission system additions. Under the UPP, the cost of the new transmission additions would be directly allocated to parties that benefit from the addition. This allocation methodology for MISO load is currently being addressed in the Regional Expansion Criteria and Benefits task force.

The UPP maintains through May 31, 2008 the zonal rate structure already in place in the MISO and PJM regions with respect to the costs of existing facilities. It also allocates costs of new facilities to beneficiaries or zones in accordance with Schedule 6 of the PJM Operating Agreement, Schedule 12 of the PJM Open Access Transmission Tariff, and comparable policies in MISO to be filed as MISO's RECB Task Force process determines. Finally, the UPP will provide for allocating an RTO's new facility costs to entities in another RTO when the first RTO's facilities provide benefits in the second RTO's footprint. The proposal is also supposed to eliminate Regional Through-and-Out Rates ("RTORs") by December 1, 2004.

This proposal will cost the Companies $1 million annually until May 31, 2008, at which time a different, yet unknown proposal will be created.

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Question No. 3

Responding Witness: Paul W. Thompson

Q-3. Refer to the Supplemental Testimony of Paul W. Thompson ("PWT"), page 3, lines 5-12.

a. Under the MISO Energy Market Tariff ("EMT"), will LG&E and KU be able to fully self-schedule their generation to meet their load requirements?

b. Will LG&E or KU incur any new or additional costs as a member of MISO to self-schedule their generation to meet their load requirements?

A-3. a. No, and the term "self-scheduling" is a misnomer because "self-scheduling" actually makes the Companies price-takers for their own generation. Load requirements must ultimately be met in real time. Due to the EMT provisions relating to the Day-Ahead must offer and RAC processes, LG&E/KU cannot be assured of having available capacity in real-time sufficient to serve native load customers.

b. Yes, "self-scheduling," i.e., price-taking of the Companies' own generation, does not help LG&E/KU to avoid the following costs:

- LMP settlement for congestion & losses
- Share of revenue sufficiency guarantee associated with MISO's Day-Ahead Security Constrained Unit Commitment process
- Share of costs associated the Reliability Assessment Commitment revenue sufficiency guarantee billing determinants
- Schedule 17
- Various uplifts associated with the risks identified in the risk matrix included in testimony submitted by Mr. Gallus

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Question No. 4

Responding Witness: Mark S. Johnson

Q-4. Refer to PWT, page 6. Under the MISO EMT, will LG&E and KU be able to comply with the provisions of KRS 278.214, which requires retail bundled load to have the highest curtailment priority on the LG&E/KU transmission facilities in the event of a transmission emergency?

A-4. The Companies do not believe that the MISO EMT affects their ability to comply with KRS 278.214. Nonetheless, the Companies remain concerned that there exists a conflict between federal and state law on this issue. That is why the Companies are currently seeking clarification on this issue in litigation before a federal district court.

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Question No. 5

Responding Witness: Mathew J. Morey

Q-5. Refer to the Supplemental Testimony of Matthew J. Morey, page 6, Table 1 ("Morey Table 1"). Provide a schedule that includes the following information for each cost shown on Morey Table 1 to be incurred by LG&E and KU as a member of either MISO, PJM Interconnection, LLC ("PJM"), or Southwest Power Pool ("SPP").

a. A breakdown of each cost into its components.

b. The billing determinants used to calculate each component of each cost.

c. The applicable rate schedule that would impose each cost component on LG&E and KU.

d. A description of each cost component that would be incurred other than under a rate schedule.

A-5. a. The costs incurred by LG&E and KU as a member of either MISO, PJM Interconnection, LLC or Southwest Power Pool are as described as follows:

MISO: Implementation and Administration Charges – covers charges under Schedules 10, 16 and 17. The following table provides the breakdown of these costs into their respective components.

	Schedule 10 Charges				
	Rate	**KU**	**LG&E**	**OSS**	**COMBINED**
2005	0.15	$ 3,271,735	$ 1,898,513	$ 945,240	$ 6,115,487
2006	0.15	$ 3,340,977	$ 1,930,474	$ 746,225	$ 6,017,675
2007	0.15	$ 3,439,464	$ 1,953,624	$ 602,048	$ 5,995,136
2008	0.15	$ 3,529,533	$ 1,989,964	$ 621,390	$ 6,140,888
2009	0.1474	$ 3,535,161	$ 1,986,672	$ 598,998	$ 6,120,831
2010	0.143	$ 3,489,082	$ 1,962,279	$ 631,469	$ 6,082,831
	Total	$ 20,605,951	$ 11,721,525	$ 4,145,370	$36,472,846
	Schedule 16 Charges		**95% FTR Annual Peak**		
	Rate	**KU**	**LG&E**	**OSS**	**COMBINED**
2005	0.058	$ 1,963,043	$ 1,268,955	0	$ 3,231,998
2006	0.0649	$ 2,243,026	$ 1,443,681		$ 3,686,708
2007	0.0649	$ 2,308,918	$ 1,460,965		$ 3,769,883
2008	0.0616	$ 2,248,931	$ 1,412,823		$ 3,661,753
2009	0.0616	$ 2,292,505	$ 1,412,823		$ 3,705,327
2010	0.0506	$ 1,915,553	$ 1,200,116		$ 3,115,669
	Total	$ 12,971,976	$ 8,199,362	$ -	$21,171,338
	Schedule 17 Charges				
	Rate	**KU**	**LG&E**	**OSS**	**COMBINED**
2005	0.077	$ 3,358,981	$ 1,949,140	$ 485,223	$ 5,793,344
2006	0.0803	$ 3,577,072	$ 2,066,894	$ 399,479	$ 6,043,445
2007	0.0792	$ 3,632,074	$ 2,063,027	$ 317,881	$ 6,012,982
2008	0.0759	$ 3,571,888	$ 2,013,844	$ 314,423	$ 5,900,155
2009	0.0748	$ 3,587,924	$ 2,016,324	$ 303,969	$ 5,908,217
2010	0.0616	$ 3,005,979	$ 1,690,579	$ 272,018	$ 4,968,575
	Total	$ 20,733,917	$ 11,799,807	$ 2,092,993	$34,626,718

For PJM, an average per MWh rate was applied for Administration charges, and therefore there is no breakdown that can be accomplished.
For SPP, an average per MWh rate was applied for Administration charges, and therefore there is no breakdown that can be accomplished.

For Miscellaneous Uplift Charges, calculated for the MISO RTO option, there is no specific breakdown of those costs, as they were advanced from the First CB Study, and in that study were assumed to be a conservative estimate of the uplift costs associated with various costs incurred by the MISO RTO in providing services in the Day 2 Markets that could not be directly assigned to market participants and transmission customers.

For Schedule 21 Uplift Charges, please refer to the Workpapers to Accompany the Supplemental Investigation, page 18 of 41, as submitted on

September 30, 2004, that describes the source of the estimate of the share of costs that is expected to be borne by LG&E and KU.

b. The billing determinants for the Administration charges for each of the RTO options are contained in page 14 of 41 in the Workpapers Accompanying the Supplemental Investigation. There is no billing determinant for Miscellaneous Uplift charges in the MISO RTO Base Case. The billing determinant for Schedule 21 Uplift charges in the MISO RTO Base Case is the energy ratio share, and can be found on page 8 of 41 in the Workpapers to Accompany the Supplemental Investigation.

c. Applicable rate schedules are as follows:

   MISO: Administration Charges: Schedules 10, 15 and 17; Schedule 21 for uplift.
   PJM: Schedule 9.
   SPP: Schedule 1.
   Transmission congestion charges are governed by:
   MISO: OATT, Section IV Financial Transmission Rights (p 602 ff)
   PJM: Attachment K to the PJM OATT
   SPP: Not applicable.

d. A description of each cost component that would be incurred that is not covered under a schedule within an RTO's OATT is provided by reference to the Workpapers to Accompany the Supplemental Investigation, pages 21 through 23 of 41. Each of these workpapers thus provides a schedule of the costs and the revenues incurred under the three RTO cases considered in the Supplemental Investigation that are not covered by a schedule within the RTO's OATT.

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Question No. 6

Responding Witness: Paul W. Thompson/Mathew J. Morey

Q-6. What cost per megawatt hour would be charged to LG&E and KU to self-schedule their generation to meet their load under each of the following assumptions:

a. Continued membership in MISO.

b. Membership in PJM.

c. Membership in SPP.

A-6. a. The costs are as listed in the response to the Question No. 5. Self-scheduling exposes LG&E/KU to the following additional costs:

- Share of revenue sufficiency guarantee associated with MISO's Day-Ahead Security Constrained Unit Commitment process
- Share of costs associated with the Reliability Assessment Commitment revenue sufficiency guarantee billing determinants

b. PJM's administrative costs currently total \$.54/MWh. In a presentation to the PJM Members' Committee dated March 25, 2004, PJM projected the following ranges for these costs into 2007:

2005	2006	2007
\$.42-.56/MWh	\$.41-.53/MWh	\$.40-.53/MWh

LG&E/KU understand that self-scheduling in PJM also exposes the Companies to additional costs resulting from sharing in the cost of PJM's unit commitment processes.

c. SPP currently has one administrative schedule, Schedule 1, that today, to LG&E/KU's best information, stands at $0.14/MWh. LG&E/KU are unaware of any additional costs associated with self-scheduling in the proposed SPP market.

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Question No. 7

Responding Witness: Martyn Gallus/Mathew J. Morey

Q-7. Are each of the costs listed in the response to Question 6 above included in Morey Table 1? If no, explain why not.

A-7. Yes.