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October 7, 2004
VIA HAND DELIVERY

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

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

Dear Ms. O'Donnell:

Enclosed please find 10 copies of the Midwest ISO's Data Requests to LG&E/KU, to be filed in the above-referenced proceeding. The Midwest ISO sent the original copy of these requests to the Commission for filing via first-class U.S. mail on October 6, 2004.

Thank you for your assistance in this matter.

Sincerely,

Benjamin D. Allen

Enclosures

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

OCT 07 2004

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

Data Requests to LG&E and KU from Midwest Independent Transmission System Operator, Inc.

Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), pursuant to the Commission's scheduling orders dated August 19 and September 28, 2004, hereby submits the attached data requests to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"). For the purpose of these requests, the Midwest ISO refers LG&E and KU to the instructions accompanying its previous initial and supplemental data requests, filed October 6 and October 30, 2003, respectively. The acronyms and capitalized words used in the attached set of data requests are as defined or used in the supplemental testimony filed by the Midwest ISO and LG&E/KU on September 29, 2004.

Respectfully submitted,

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By: ______________________________
ATTORNEYS FOR MIDWEST INDEPENDENT
TRANSMISSION SYSTEM OPERATOR, INC.

CERTIFICATE OF FILING AND SERVICE

I hereby certify that on this the 6th day of October, 2004, the original and copies of these Data Requests to LG&E and KU, respectively, were sent via first-class U.S. Mail for filing with the Commission and service on:

Michael S. Beer
Beth Cocanougher
LG&E ENERGY CORP.
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500 West Jefferson Street
Louisville, KY 40202

____
Attorney for Midwest Independent
Transmission System Operator, Inc.

General

1. Provide all data, input files, intermediate results, or other information necessary to replicate the analyses presented.

2. Provide all supporting studies, derivations, or workpapers for the analyses presented.

3. To the extent not already identified in response to Data Request 2, identify the source of any numerical data (historical, projected, or estimated) used in the analyses presented.

4. Provide all supporting studies, derivations, or workpapers for each numerical data or assumption used in the Supplemental Investigation presented by Mathew J. Morey for which LG&E/KU was the source.

5. Do the analyses and conclusions contained in LG&E/KU's supplemental testimony take into account the FERC Order issued September 16, 2004, in *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235? If so, describe how and to what effect.

Paul W. Thompson

6. Provide a copy of any objections to the formation of the Midwest ISO, LG&E/KU's membership in the Midwest ISO, or the Midwest ISO's centralized dispatch and energy markets proposal, whether presented to FERC or the Kentucky Public Service Commission, by LG&E/KU or on its behalf, including, but not limited to, any and all documents, presentations, letters or other communications not filed in a public or noticed docket, case, or other proceeding. (PWT Supp. 2 *ll.*21-22)

7. Provide any documentation, evidence or other analysis possessed by or performed by LG&E/KU — other than the cited "Business Watch" item (Exh. PWT-1) — for the contention by Paul W. Thompson that withdrawal from the Midwest ISO would not have an "unduly negative effect" on the Midwest ISO's operations under its EMT. (PWT Supp. 6 *l.*19)

Mark S. Johnson

8. Mark S. Johnson opines that "from a reliability standpoint, coordination service should be the same regardless of whether it is provided by MISO or any other NERC certified Reliability Coordinator." (MSJ Supp. 2 *ll.*16-18) Provide a list of all NERC certified Reliability Coordinators and the elements of the coordination service provided by each.

9. Compare TVA and Midwest ISO reliability coordination services, tariff administration services, and the cost therefor. (MSJ Supp. 3 *ll.*3-7)

10. Provide the load characteristics of Associated Electric Cooperative, Inc. ("AECI") — and the source of that information — considered in opining that AECI "has load characteristics similar to LG&E/KU." (MSJ Supp. 3 *l*.3)

11. Provide the date on which the interconnections map, Exh. MSJ-1, was last revised and list all changes, including revisions to facility ratings, topology and system impacts that have been proposed or implemented to the transmission lines and systems depicted since that last revision date.

<u>**Martyn Gallus**</u>

12. Provide the discount rate used for the net present values presented in Martyn Gallus's Supplemental Testimony (*e.g.*, MG Supp. 3 Table 1).

13. What effect on prices did LG&E/KU's RTO membership status have on electricity prices in the LG&E/KU analysis? (MG Supp. 5 *ll*.4-5 & 19-22) Provide any and all analysis possessed by or performed by LG&E/KU regarding these effects.

14. If LG&E/KU contends that too many TLRs are assumed by the Midwest ISO in the TORC case (MG Supp. 5 *l*.23 – 6 *l*.1), provide the assumptions about TLRs made in each of the three TORC cases presented in the LG&E/KU analysis.

15. With respect to the comparison of off-system sales and purchases between the Midwest ISO case and the TORC case (MG Supp. 6 *l*.7 – 7 *l*.10):

    a. Identify the TORC case on which the comparison is based.

    b. How did the comparison treat months before the start-up of the Day 2 markets?

16. With respect to the comparison of the projected volumes for off-system sales and purchases to LG&E/KU's historical experience (MG Supp. 8 *l*.3 – 9 *l*.3):

    a. Provide for 2004, in On Peak, Off Peak, and Total categories comparable to those given in Tables 5 and 6:

        i. available historical data and

        ii. projections or estimates for the total year or the portion of the year not covered by the available historical data

    b. Provide for each year 2004-2010, inclusive, in On Peak, Off Peak, and Total categories comparable to those given in Tables 5 and 6, the volumes of combined company off-system sales and purchases most recently projected by LG&E/KU but that do <u>not</u> factor in the operation of Day 2 markets in the Midwest ISO.

17. There is reference to "native load" throughout the Supplemental Testimony of Martyn Gallus (*e.g.*, MG Supp. 8 *l.*15, 14 *ll.*12-13, 15 *l.*11, Exh. MG-1 & Appx. B).

    a. Identify the components of that native load (*e.g.*, municipalities, wholesale or retail customers, customers served pursuant to Grandfathered Agreements).

    b. Name each native-load customer that does <u>not</u> receive electric service for ultimate consumption (*i.e.* is a retail service customer). In addition, with respect to each such customer, state whether the customer receives service in Kentucky. (MG Supp. 14 *l.*2)

    c. For each statistic, statement, or contention about "native load" in the Supplemental Testimony, Exh. MG-1, and Appendix B, state whether it is true about or applicable to retail native load and, if so, to what extent. <u>For example,</u> the averment that LG&E and KU "serve approximately 99% of their native load with their own generation both historically and in the PROSYM analysis" (MG Supp. 8 *ll.*15-16), may be true of retail native load historically but some different percentage might have resulted from the PROSYM analysis.

18. For costs to participate in Day 2 markets (MG Supp. 10 *ll.*6-13):

    a. Provide any and all business plans, organization charts, mission statements, or itemized and approved budgets for such costs.

    b. List the job title and description of every employee hired as a result of LG&E/KU preparations to implement the Midwest ISO Day 2 markets.

    c. List the number of personnel and full time equivalents ("FTEs") employed by LG&E/KU for 2002-present, as well as the budgeted number of personnel and FTEs for its participation in the Day 2 markets next year.

    d. Provide an itemized breakdown of:

        i. the approximately $1 million already contracted for or otherwise allocated for trading implementation

        ii. the $950,000 expected to be spent for market trading support tools

    e. Of the costs itemized in subpart a, what portion will be avoided if:

        i. LG&E and KU withdraw from the Midwest ISO at the beginning of 2006?

        ii. LG&E and KU participate in the Day 2 markets, but only as non-members of the Midwest ISO?

19. Martyn Gallus testifies about hedging against congestion costs in the Day 2 markets. (MG Supp. 10 *l*.17 – 11 *l*.18)

    a. Provide an itemized breakdown of LG&E/KU's congestion costs or costs associated with redispatch of LG&E/KU's generation assets due to transmission constraints on an annual or transactional basis for the most recent five-year period, including this year.

    b. Provide any analysis LG&E/KU possesses related to the current costs of congestion or costs associated with redispatch of LG&E/KU's generation assets due to transmission constraints between LG&E/KU generating units and their load zones (*see* MG Supp. 12 *ll*.16-17, 13 *ll*.1-2).

20. Martyn Gallus avers that LG&E/KU anticipates "having to make additional investments in personnel and systems" relating to the Day 2 markets' settlement process. (MG Supp. 15 *ll*.11-13)

    a. Provide any and all business plans, organization charts, mission statements or itemized and approved budgets for Mr. Gallus' business group and any other business groups of the Companies impacted or effected by these additional investments in personnel and systems for the most recent five-year period.

    b. Provide any and all existing employment opportunity postings for LG&E/KU including job title, description, responsibilities and reporting requirements.

21. Martyn Gallus testifies about responsibility for commitment costs — start-up and non-load costs — associated with self-scheduled resources. (MG Supp. 15 *ll*.16-19) Provide the start-up and no-load costs for all LG&E/KU generating resources for the most recent five-year period.

22. Provide any analysis or evidence LG&E/KU possesses regarding LG&E/KU's subjection to the RAC guarantee payment costs. (MG Supp. 16 *ll*.6-8)

23. Provide any analysis or evidence LG&E/KU possesses regarding those Day 2 market participants that would not meet LG&E/KU's "strict creditworthiness standards." (MG Supp. 17 *l*.5 – 18 *l*.6)

24. In a "risk matrix" (MG Supp. 19), Martyn Gallus identifies risks perceived to be associated with the Midwest ISO Day 2 formation process and whether each such risk is also present in various alternatives LG&E/KU has evaluated. Identify any risks to LG&E/KU associated with those other alternatives (PJM, SPP, TORC), but that are not present in the Midwest ISO alternative.

25. Provide a concrete, actualized example of the LG&E/KU "ability to identify cost-reducing day-ahead and real-time trades." (MG Supp. 20 *ll.*1-2)

26. In Exhibit MG-1, net present value of costs and revenue is to 2003. Provide the net present value of the costs and revenue to 2004.

27. As described in MG Appendix B, the methodology used in Martyn Gallus's analysis relies on various databases and forecasts. *See, e.g.*, MG Appx. B, pp. 3-4, 5, 9.

    a. Contrast the most recent data and forecasts available to LG&E/KU with the data regarding LG&E and KU (or their combination) from

        i. Platt's 2004 BaseCase database (generation data)

        ii. Platt's 2004 BaseCase database (load: 2002 vintage)

        iii. NERC MMWG Summer 2005 base power flow model (created in 2003)

    b. Provide

        i. the Hill & Associates forecasts used regarding coal prices (Spring 2004) and regarding NOx and SO_2 emission allowance prices

        ii. the native load forecast developed in February 2004 (MG Supp. Appx. B p.8)

    c. Provide the weights assigned to forward price data in the coal price forecast.

28. In the PROSYM analysis, three Transaction Groups connected to LGEE were used to represent the primary markets — INDI #1 for the Midwest ISO market prices, SOKYE #90 for PJM market prices, and TVA #32 for TVA market prices. (MG Appx. B pp. 5-6)

    a. List the utilities within INDI #1, SOKYE #90, and TVA #32 that have direct physical interconnections with LGEE.

    b. Are the LGEE direct physical interconnections with INDI #1, SOKYE #90, and TVA #32, respectively, the only direct physical interconnections it has with other Midwest ISO members, with PJM (assuming AEP membership therein), and TVA? If not,

        i. identify the other such Transaction Groups with which it is connected and

        ii. provide the results of any modeling done with such other Transaction Group as a primary market.

29. LG&E/KU reordered the MIDAS price forecasts to correspond to the LG&E/KU load forecast. (MG Appx. B p.6)

    a. Provide the chronological load shapes for the LG&E/KU load forecast used in PROSYM and in MIDAS.

b. Explain why reordering the MIDAS price forecasts did not change the monthly average electricity prices.

30. MG Appx. B, p.6, refers to "average annual electricity prices by peak type for three cases." Identify the case that was studied in addition to the RTO Case and Standalone case and provide the average annual electricity prices calculated for that case.

31. Provide the data or other evidence available to LG&E/KU about the "difference in the wholesale electricity prices between the BREC and INDI transaction groups." (MG Appx. B p.7)

32. For the LG&E/KU production cost modeling, "it was assumed that LGE/KU built no new generating resources." (MG Supp. Appx. B p.7)

    a. How was this assumption implemented in the model?

    b. The reserve margin trigger in MIDAS is 12%. (MG Supp. Appx. B p.3)

        i. Why was 14% used to trigger LG&E/KU purchases of peaking capacity from the market? (MG Supp. Appx. B p.3)

        ii. What would be the qualitative effect on the results of using 12% as the trigger for such purchases?

33. Different hurdle rates are presented in Table 1 (MG Supp. Appx. p.5) and Table 5 (MG Supp. Appx. p.9).

    a. Explain why these rates are different.

    b. What are the units in Table 5 for Hurdle Rates?

    c. If it was assumed for the TORC case(s) that it would "be costless for LGE/KU to sell energy off-system to any market since it would be paying itself for transmission" (MG Supp. Appx. p.9), explain why the Hurdle Rate is greater than zero for sales to TVA in Case 4.

    d. If it was assumed for sales to the TVA market that LG&E/KU would receive back only "approximately 45% of every transmission expense dollar" (MG Supp. Appx. p.9), explain why the Hurdle Rate is zero for sales to TVA in Cases 2 and 3.

34. MG Supp. Appx. B, pp. 8-10, discusses the assumptions and calculations for physical transfer limitations between LG&E/KU and the MISO, PJM, and TVA markets and presents the results in Table 5.

a. Limitations were calculated using Cinergy as a proxy for the MISO market and AEP as the proxy for the PJM market.

   i. Were limits for transfers between LG&E/KU and the TVA markets calculated using all points of connection between LG&E/KU and TVA? If not, how were those limits calculated?

   ii. Why were proxies used for the MISO and PJM markets rather than including all points of connection between LG&E/KU and those markets?

   iii. Provide any calculations of limits relating to the MISO or PJM markets using different proxies or not using proxies.

   iv. Compare the data used for Cinergy to corresponding data for INDI #1.

   v. What would be the expected qualitative effect of calculating transfer capability limits for all available connections between LG&E/KU and the Midwest ISO compared with those calculated for transfer capability between LG&E/KU and Cinergy?

b. What are the units of the XM Limits presented in Table 5?

c. Case 2 and Case 4 are described as applying more restriction and less restriction, respectively, than in Case 3. (MG Supp. Appx. B pp. 9-10)

   i. Describe precisely how more restriction and less restriction on transmission transfer limits was applied in Case 2 and Case 4, respectively, than in Case 3.

   ii. Were "all equipment ratings reduced in MUST by 9.3% in determining the transfer limitations" (MG Supp. Appx. B p.8) for each case of the TORC analysis? If not, what reduction was applied in each case?

35. Were wholesale electricity prices varied identically for Cases 1-4? (MG Supp. Appx. B p.9) If not, how were those prices varied for the four cases?

<u>**Michael S. Beer**</u>

36. Provide a citation and an explanation for LG&E/KU's "obligation to serve retail consumers in the Commonwealth of Kentucky". (MSB Supp. 2 *ll*.9-10)

37. Michael S. Beer contends that "allotting a greater number of FTRs to certain utilities acts as a subsidy of those utilities' congestion costs by other transmission consumers." (MSB Supp. 4 *ll*.18-19)

   a. To what does the comparative "greater" refer? (*i.e.*, the number of FTRs allotted to certain utilities are greater than what?)

b. Provide any data, analysis, or other evidence LG&E/KU has that such an allotment of "a greater number of FTRs to certain utilities" is proposed to occur or will occur?

c. Provide any data, analysis, or other evidence LGE&E/KU has that relates to the specific costs to LG&E/KU as a result of the allotment of a greater number of FTRs to certain utilities.

38. Michael S. Beer states that LG&E and KU "use their interruptible customers to manage their own system loading." (MSB 5 *ll*.5-6)

   a. Are the terms and conditions of LG&E/KU service to interruptible retail customers established in tariffs or special contracts approved by and on file with the Commission? If so, provide such terms and conditions.

   b. Describe LG&E/KU's understanding, and the basis therefor, of the source and limits on the Midwest ISO's ability in Day 2 "to instruct the Companies which interruptible customers to interrupt so MISO can manage regional loading." (MSB Supp. 5 *ll*.3-4)

39. Provide copies or complete citations to "the Commission's and the Governor's expressed views and policies concerning RTOs" forming referenced LG&E/KU's belief. (MSB Supp. 5 *ll*.18-19)

40. With respect to start-up and no-load costs (MSB Supp. 6 *l*.9 – 7 *l*.4):

   a. Identify the cost-causer with respect to

      i. self-scheduled generation

      ii. generation that is not self-scheduled

   b. Identify who now bears in the first instance start-up and no-load costs for

      i. generation used to serve the generator's own load obligations

      ii. generation made available in its entirety to the market

41. Provide citations to the Commission's current jurisdiction over LG&E/KU's operation of its generation assets, (MSB Supp. 8 *ll*.16-17), and over service of non-retail or non-Kentucky native load?

42. Michael S. Beer refers to "Kentucky's regulatory framework" and a principle that generation assets are to serve native load, "not to speculate in the wholesale markets." (MSB Supp. 10 *ll*.9-14)

   a. Provide a list of all wholesale energy sales and purchases for each of the prior five years, showing the megawatt capacity value and counterparty of each purchase or sale.

b. Provide a list of all currently effective contracts, arrangements or agreements to which LG&E/KU is a party involving the purchase or sale of wholesale energy showing the counterparty our counterparties to each contract, arrangement or agreement and the total megawatt capacity value associated therewith.

c. Provide a list of all contracts, arrangements or agreements to which LG&E/KU is a party involving the purchase or sale of wholesale energy showing the counterparty or counterparties to each contract, arrangement or agreement and the total megawatt capacity value associated therewith that will be in effect in 2005.

43. Provide citations for any and all "Commission directives" that currently affect LG&E's and KU's management of their own system loading with respect to interruptible retail customers. (MSB 13 *ll.*20-23)

44. Identify (by section numbers or other pinpoints) provisions in the EMT and the PSSA that are "apparently conflicting"? (MSB 16 *ll.*15) Provide a copy of the referenced PSSA.

Mathew J. Morey

45. In describing TORC scenarios, Mathew J. Morey states that "the hurdle rates were set equal to the hurdle rates in the MISO Base and the PJM RTO Cases." (MJM 6 *ll.*2-3) For which TORC case(s) were the hurdle rates set equal to those in the MISO Base and PJM RTO Cases?

46. With respect to the Present Values presented in Table 1 (MJM Supp. 6):

a. Compare the results in the column for the "MISO RTO BSE Case" to those in the column for remaining a Midwest ISO member in the First CB Study (direct and rebuttal).

b. Is the Non-recurring Cost (Exit Fee) present valued to 2003? If so, when is the cost assumed to be incurred?

47. What discount rate was used for the net present values presented in Mathew J. Morey's Supplemental Testimony (*e.g.*, MJM Supp. 6, Table 1; the tables in Exh. MJM-2 Appx. A)?

48. Describe the calculation of "the simple payback period" on the Exit Fee payment (MJM Supp. 8 *ll.*2, 5) given a particular difference in net recurring cost.

49. Provide the outputs from the production cost modeling that were actually used as "inputs to the second part that involved financial evaluation modeling." (MJM Supp. 9 *ll.*2-3)

50. What period of time — beginning on what date — did Christensen Associates have to conduct the Supplemental Investigation? (MJM Supp. 14 *ll.* 7-9)

51. With respect to the list of "drivers" (MJM Supp. 15 *l*.16 - MJM *l*.14):

    a. Are there any factors identified and quantified in the Supplemental Investigation that are not included in the list? If so, identify those factors and provide any quantification or other analysis of those factors.

    b. Which factors listed were not explored in the First CB Study?

    c. Of the factors listed which were explored in the First CB Study, identify those for which no "refinements to the estimates" were made.

52. The Supplemental Investigation assumes that a given standard of reliability "can be met under all options." (MJM Supp. 17 *l*.21 – 18 *l*.4)

    a. What is that "standard of reliability"?

    b. Is the standard identified in response to subpart a now being met? If so, is it now being exceeded?

53. Provide, for inspection and copying, each publication, professional paper, conference presentation, and testimony listed in Exhibit MJM-1 (pp. 2-7). Also provide any publication, paper, presentation, or testimony not listed in Exhibit MJM-1 that relates to any electric power or power regulation issue.

54. Section 2.2 of the Supplemental Investigation describes an assumption about curtailment that relates to the Kentucky Power stipulation. (Exh. MJM-2 p.10) Does the Supplemental Investigation treat this assumption as a difference between the MISO Base Case and the PJM Case? If so, what is the effect of this difference?

55. Provide any data or analysis, from FTR revenue inadequacy experience in PJM or otherwise, supporting the assumption that payouts by the Midwest ISO to FTR holders will be "5% less than the nominal value of the target FTR allocations." (Exh. MJM-2 p.10 fn.6)

56. Mathew J. Morey opines that "[c]ost-benefit studies of RTOs typically evaluate the benefits and costs of implementing a regional bid-based security constrained economic dispatch (real-time) energy spot market from the perspective of the region as a whole" and that the study conducted by the Midwest ISO in this proceeding is such a study. (Exh. MJM-2 p.16 & fn. 21). Identify each aspect of the benefit-cost study presented in the Midwest ISO testimony prefiled on December 29, 2003, in which it is contended that such benefits and costs were evaluated "from the perspective of the region as a whole."

57. Provide the data, analysis, or other basis for the statement that "marginal losses tend to be nearly double of average losses." (Exh. MJM-2 p.19)

58. Supplemental Investigation § 6.3.3 discusses FTRs under the Midwest ISO and PJM, and states the assumption that "the same number of FTRs will be allocated to the Companies in either RTO case, and the nominal value of those FTRs will be the same. (Exh. MJM-2 p.22)

    a. What are the types of FTRs and the number of each type of FTR assumed to be allocated to LG&E/KU in either RTO case?

    b. What is the nominal value of those FTRs assumed to be allocated to LG&E/KU?

59. State the transmission revenues assumed to be received in the TORC and SPP cases. (Exh. MJM-2 p.25)

60. Identify the source and provide the basis for the "estimate of the cost of Reliability Coordination and OASIS services provided by an independent third party" to which reference is made in Supplemental Investigation § 7.3. (Exh. MJM-2 p.28)

61. Provide, in electronic form, the Excel spreadsheet that consolidates quantitative information with assumptions and converts them into revenues and costs, and which is described in Supplemental Investigation § 8.2 (Exh. MJM-2 p.28).

62. Among the inputs to the financial evaluation listed in Supplemental Investigation § 8.2.1 is an estimate of the "MISO exit fee (paid to MISO under the all non-MISO Cases)." (Exh. MJM-2 p.29)

    a. What is the estimated nominal amount of the exit fee?

    b. What is the source of the estimate?

    c. On what date is it assumed that the exit fee would be paid by LG&E/KU?

    d. Provide the calculations, underlying data, or other derivation of the exit fee estimate.

63. An assumption described in Supplemental Investigation § 8.2.2 as being common to all of the cases examined for all years of the study period is an inflation rate of 2.5%. (Exh. MJM-2 pp. 29-30)

    a. Provide all data, analyses, or other bases for the assumed inflation rate of 2.5%.

    b. Was the assumed inflation rate applied to all costs and revenue factors? If not, identify either those factors to which it <u>was</u> applied or those to which it <u>was not</u> applied.

    c. For any factor to which both the 2.5% inflation rate and the 7.0% discount rate was applied, would the result be the same as if a 4.5% discount rate had been applied?

64. Provide the "evidence from the PJM FTR auctions in the 2003/2004 period" that was used in estimating revenues for LG&E/KU as a member of PJM (Exh. MJM-2 p.34), and the derivation of the estimate.

65. With respect to the SPP RTO Case Administrative Costs discussed in Supplemental Investigation § 9.2 (Exh. MJM-2 p.34):

    a. What is the source or derivation of the $0.15/MWh (presented as an average rate)?

    b. State the LG&E and KU (or combined) MWhs used to derive the estimated Administrative Costs for the study years.

66. Itemize the $1 million in spending that both was assumed in the First CB Study under the TORC option <u>and</u> is also required spending under the Day 1 Markets and in preparing for the Day 2 Market. (Exh. MJM-2 p.35)

67. What is the "MISO Rate Sensitivity Case 10%" (MJM Supp. Appx. B p.1), and how was it used?

68. To what does "Average Growth Rate of Combined Companies forecast 2.04%" refer (MJM Supp. Appx. B p.1), and how was it used?

69. Provide, in electronic form, each Excel spreadsheet listed or referred to as a source in MJM Supp. Appx. B.

<u>Susan F. Tierney</u>

70. Susan F. Tierney references public interest statements and findings by the Commission. (SFT 8 *ll*.15-17). Identify and provide a copy of each and every Commission order or other document that she relied upon in reaching her determination as to the public policy goals that she claims are relevant in the Commission's investigation.

71. Provide a copy of, or make available for inspection and copying, each and every transcript of testimony, publication, report, article or other documents listed by Susan F. Tierney in Attachment A to her testimony that relates to the regulation of the electric utility industry.

72. Provide a copy of, or make available for inspection and copying, each and every document and workpaper relied upon by Susan F. Tierney in the preparation of her testimony.

Note: Headings are provided to indicate whether the requests are addressed to all of the testimony prefiled by LG&E/KU on September 29, 2004, or to testimony given by a particular individual.