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June 4, 2004

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JUN 4 2004
PUBLIC SERVICE COMMISSION

HAND DELIVERY

Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RE: ***Application of Louisville Gas and Electric Company for an Adjustment of its Gas and Electric Rates, Terms and Conditions***
Case No. 2003-00433

Application of Kentucky Utilities Company for an Adjustment of its Electric Rates, Terms and Conditions
Case No. 2003-00434

Dear Ms. O'Donnell:

Enclosed please find and accept for filing two originals and ten (10) copies of Louisville Gas and Electric Company's and Kentucky Utilities Company's Joint Post-Hearing Brief in the above-referenced matters. Please confirm your receipt of this filing by placing the stamp of your Office with the date received on the enclosed additional copies and return them to me in the enclosed self-addressed stamped envelope.

Should you have any questions or need any additional information, please contact me at your convenience.

Very truly yours,

Kendrick R. Riggs

KRR/ec
Enclosures
cc: Parties of Record

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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JUN 4 2004

PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS	)	**CASE NO. 2003-00433**

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS	)	**CASE NO. 2003-00434**

JOINT POST-HEARING BRIEF OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

Executive Summary

Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") are before this Commission seeking base rate increases which are essential to the Companies' continued safe and reliable operation. The evidence of record fully supports the complete relief requested by the Companies in their Applications, including but not limited to the rate increases being sought. However, the record also shows that the parties to these proceedings have entered into a Partial Settlement Agreement, Stipulation and Recommendation, filed in Case Nos. 2003-00433 and 2003-00434 on May 12, 2004, ("Partial Settlement, Stipulation and Recommendation") which reflects a unanimous agreement by all parties on all issues, save one, including the revenue requirement for LG&E's gas operations. For the one issue on which there is not unanimous agreement -- the revenue requirements for LG&E's and KU's electric operations -- a stipulation by all parties, except the Office of the Attorney General for the Commonwealth of Kentucky ("AG"), was reached. The unanimous agreement as to the revenue requirement for LG&E's gas operations and the stipulated amount of the revenue requirements for LG&E's and KU's electric operations are significantly less than the Companies' original requests, and represent a very substantial compromise by the Companies. The Companies request that the unanimous agreement of the parties, including but not limited to the revenue requirement for LG&E's gas operations be approved, and respectfully submit that the stipulated amounts of the revenue requirements for LG&E's and KU's electric operations are the minimum amounts that should be awarded.

The Companies have long histories of operating efficiently and continually striving to optimize savings in the face of rising costs. KU has not had a base rate increase for over twenty years;[1] and LG&E has not had an electric base rate increase for over thirteen years[2] or a gas base rate increase in more than three years.[3] Indeed, the Companies sustained significant reductions in base rates in 2000 as a result of the performance-based ratemaking proceedings (Case Nos. 98-426 and 98-474) (the "PBR proceedings").[4] Since their merger in 1998, KU and LG&E have been able to extend their efficient performance by taking advantage of synergies, combined work practices, lower overhead and administrative staff expenses, and other economies of scale. All of those efforts have allowed the Companies to continue providing safe and reliable service without the need for a base rate increase for years.

In recent years, however, the Companies have seen growing customer bases,[5] made significant investments in plant,[6] and been faced with a number of other cost pressures such as employee pension and post-retirement expenses, property insurance costs, Midwest Independent Transmission System Operator, Inc. ("MISO") Schedule 10 costs, and labor and other cost increases.[7] The Companies are not able to achieve further significant efficiencies to address those rising costs. As a result, the Companies' are no longer earning a fair rate of return.[8] For example, for the twelve months ended September 30, 2003, LG&E's return on equity was 5.96% and its return on capital was 4.58% for electric operations, well below the 11.5% return on common equity and the overall cost of capital of 8.47% approved by the Commission in Case

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[1] Direct Testimony of Victor A. Staffieri of December 29, 2003 (Case No. 2003-00434) ("Staffieri KU Direct") at 5; Direct Testimony of Paul W. Thompson of December 29, 2003 (Case No. 2003-00434) ("Thompson KU Direct") at 3; Direct Testimony of Chris Hermann of December 29, 2003 (Case No. 2003-00434) ("Hermann KU Direct") at 3.
[2] Direct Testimony of Victor A. Staffieri of December 29, 2003 (Case No. 2003-00433) ("Staffieri LG&E Direct") at 5; Direct Testimony of Paul W. Thompson of December 29, 2003 (Case No. 2003-00433) ("Thompson LG&E Direct") at 3; Direct Testimony of Chris Hermann of December 29, 2003 (Case No. 2003-00433) ("Hermann LG&E Direct") at 3.
[3] Staffieri LG&E Direct at 6; Hermann LG&E Direct at 3-4.
[4] Staffieri LG&E Direct at 5; Hermann LG&E Direct at 3; Staffieri KU Direct at 5; Hermann KU Direct at 3.
[5] Hermann LG&E Direct at 12-13; Hermann KU Direct at 13.
[6] Staffieri LG&E Direct at 7-9; Staffieri KU Direct at 6-7.
[7] Staffieri LG&E Direct at 7-9; Staffieri KU Direct at 6-7.
[8] Staffieri LG&E Direct at 6; Direct Testimony of S. Bradford Rives of December 29, 2003 (Case No. 2003-00433) ("Rives LG&E Direct") at 2-4; Staffieri KU Direct at 6; Direct Testimony of S. Bradford Rives of December 29, 2003 (Case No. 2003-00434) ("Rives KU Direct") at 2-4.

No. 98-426.[9] And, in the same period for its gas operations, LG&E earned a return on equity of 3.92% and a return on capital of 3.60%, again well below Commission-approved returns in Case No. 2000-080 of 11.25% for return on equity and 8.21% return on capital.[10] Similarly, for the twelve months ended September 30, 2003, KU only earned a return on equity of 6.22% and a return on capital of 4.63%, also well below the 11.5% return on common equity and the overall cost of capital of 9.58% approved by the Commission in Case No. 98-474.[11] Based on the analysis presented in Robert G. Rosenberg's testimony, the return on equity for the Companies' electric operations should be in the range of 10.75% – 11.25%, and Mr. Rosenberg has recommended the Commission adopt an 11.25% allowed return in these proceedings.[12] This equity return is necessary for the Companies to regain and preserve their financial health.

The Companies calculated their revenue requirements in these proceedings by using established Commission precedent or, where the Commission has not previously considered a specific issue, guidance from the Federal Energy Regulatory Commission ("FERC").[13] In doing so, as set forth in the filings accompanying their Applications, LG&E's overall revenue deficiency was calculated to be $63,764,203 for electric operations and $19,106,269 for gas operations, and KU's overall revenue deficiency was calculated to be $58,254,344.[14] All parties

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[9] Rives LG&E Direct at 4; *In the Matter of: Application of Louisville Gas and Electric Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-426, Order dated June 1, 2000.

[10] Id. at 4; *In the Matter of: Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and To Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order dated September 27, 2000.

[11] Rives KU Direct at 4; *In the Matter of: Application of Kentucky Utilities Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-474, Order dated June 1, 2000.

[12] Direct Testimony of Robert G. Rosenberg of December 29, 2003 (Case No. 2003-00433) ("Rosenberg LG&E Direct") at 2; Direct Testimony of Robert G. Rosenberg of December 29, 2003 (Case No. 2003-00434) ("Rosenberg KU Direct") at 2. Mr. Rosenberg also recommended an 11.5% return for LG&E's gas operations. However, as discussed in detail below, the parties have entered into a unanimous settlement with regard to the revenue requirement of LG&E's gas operations.

[13] Rebuttal Testimony of S. Bradford Rives of April 26, 2004 (Case Nos. 2003-00433 and 2003-00434) ("Rives LG&E and KU Rebuttal") at 4.

[14] Rives LG&E Direct at 29; Rives KU Direct at 25. As set out in Section V. below, further adjustments were made during the course of these proceedings which adjusted the amount of those revenue requirements.

except the AG have since stipulated that an annual increase in revenues of $43,400,000 for LG&E's electric operations and $46,100,000 for KU's operations would be fair, just and reasonable; and all parties, including the AG, have agreed that an annual increase in revenues of $11,900,000 for LG&E's gas operations would be fair, just and reasonable.[15]

The Companies also presented fully allocated, embedded cost of service studies which were prepared using methodologies previously accepted by the Commission, and proposed rate allocations and designs which followed those studies as closely as practicable while also giving consideration to other ratemaking objectives such as customer acceptance, gradualism and the need to maintain price stability by avoiding overly disruptive changes.[16] LG&E and KU also proposed a number of tariff changes to simplify their rate schedules and, where feasible, to harmonize language, practices and policies between the two companies.[17] All parties have since agreed on a fair, just and reasonable resolution of rate allocations, rate designs and tariff changes.[18]

The parties have also unanimously agreed to a fair, just and reasonable resolution of Case Nos. 2003-00334 and 2003-00335 (the "ESM renewal proceedings") and Case Nos. 2004-00069 and 2004-00070 (the "2003 ESM proceedings").[19] That settlement, if approved by the Commission, will allow the Companies to continue to bill and collect under the ESM for Reporting Period 2003 pursuant to the factors previously filed in the 2003 ESM proceedings, will not allow the Companies to bill or collect under the ESM for the first six months Reporting

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[15] Partial Settlement, Stipulation and Recommendation at Sections 1.1, 1.1.1, 1.1.2 and 1.2.

[16] Direct Testimony of William Steven Seelye of December 19, 2003 (Case No. 2003-00433) ("Seelye LG&E Direct") at 1, 57; Direct Testimony of William Steven Seelye of December 19, 2003 (Case No. 2003-00434) ("Seelye KU Direct") at 1, 29-30.

[17] Direct Testimony of Sidney L. "Butch" Cockerill of December 29, 2003 (Case No. 2003-00433) ("Cockerill LG&E Direct") at 2; Direct Testimony of Sidney L. "Butch" Cockerill of December 29, 2003 (Case No. 2003-00434) ("Cockerill KU Direct") at 2.

[18] Partial Settlement, Stipulation and Recommendation at 1, *et seq.*

[19] Settlement Agreement, filed in Case Nos. 2003-00433 and 2003-00434 on May 12, 2004 ("ESM Settlement Agreement").

Period of 2004, and, except for the collection for Reporting Period 2003 as described above, will terminate the ESM prospectively for the 2004 Reporting Period effective July 1, 2004.

It is essential that LG&E and KU achieve and maintain a strong financial condition so that they may continue to provide safe, reliable service to their customers. It is not in the best interest of the Companies' shareholders or ratepayers, or of the greater Commonwealth, for the Companies to remain in a weakened financial state. Approval of the requested rate increases is imperative to remedy the Companies' current financial situation. And, even with the requested increases, the Companies' retail rates will still rank among the lowest in the nation.[20]

Summary of Issues for Resolution

Extensive negotiations among the parties and Commission Staff, as discussed in the Procedural History below, produced a settlement of all but two of the contested matters in these proceedings. The issues not fully resolved are: the revenue requirement for LG&E's electric operations and the revenue requirement for KU's operations.[21]

Based on the record in these proceedings, the Companies respectfully submit that there are essentially three issues for decision by the Commission:

1. Whether to approve the ESM Settlement Agreement and that portion of the Partial Settlement, Stipulation and Recommendation (*e.g.* Section 1.2 which provides for an annual $11.9 million increase in revenues for LG&E's gas revenues) which constitutes a unanimous agreement by all the parties to the rate proceedings based on the evidence of record;

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[20] Staffieri LG&E Direct at 10; Staffieri KU Direct at 9.

[21] As discussed in more detail in the Procedural History below, the executed versions of the ESM Settlement Agreement and the Partial Settlement, Stipulation and Recommendation were filed with the Commission and were the subject of the hearing in these proceedings on May 12, 2004.

2. Whether an award to LG&E at least a $43,400,000 annual increase in revenues through changes in its electric base rates based upon the evidence of record, including the stipulation submitted by all parties, except the AG, is fair, just and reasonable; and

3. Whether an award to KU of at least a $46,100,000 annual increase in revenues through changes in its electric base rates based upon the evidence of record, including the stipulation submitted by all parties, except the AG, is fair, just and reasonable.

LG&E and KU respectfully submit that the Commission should answer the foregoing questions by approving the ESM Settlement Agreement and those portions of the Partial Settlement, Stipulation and Recommendation which constitute an agreement by all the parties to the rate proceedings, and by awarding LG&E at least a $43,400,000 annual increase in revenues and KU at least a $46,100,000 annual increase in revenues through changes in their respective electric base rates.

Procedural History

On November 24, 2003, the Companies filed their Notices of Intent to file a rate case application on or after December 29, 2003. The Companies then filed their Applications and supporting testimony and exhibits on December 29, 2003.

In the LG&E case, the AG, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Kentucky Division of Energy ("KDOE"), U.S. Department of Defense ("DoD"), The Kroger Co. ("Kroger"), Kentucky Association for Community Action, Inc. ("KACA"), Metro Human Needs Alliance ("MHNA") and People Organized and Working for Energy Reform ("POWER") were granted full intervention. The AG, KIUC, KDOE, Kroger, KACA, Lexington-Fayette Urban County Government ("LFUCG"), North American Stainless ("NAS"), and Community Action

Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc ("CAC") all were granted full intervention in the KU case.

On December 18, 2003, the Companies moved the Commission to consolidate the ESM renewal proceedings with the pending rate cases. The AG and KIUC joined in LG&E's motion, and the AG, KIUC and LFUCG joined in KU's motion. The Commission entered orders approving those consolidations on March 31, 2004.

On February 13, 2004, LG&E and KU also moved the Commission to consolidate the proposed Non-Conforming Load Service tariff case (Case No. 2003-00396) with their rate cases. On March 19, 2004, the Companies filed an Amended Motion to Consolidate to clarify that they were seeking to have Case No. 2003-00396 bifurcated and the respective portions consolidated with the KU and LG&E rate cases. That motion, as amended, was granted by the Commission on March 23, 2004.

On January 14, 2004, the Commission entered an Order suspending the Companies' proposed new rates through and including June 30, 2004, and implementing a procedural schedule. In accordance with that schedule, the parties engaged in significant discovery through the exchange of numerous data requests and responses, consisting of thousands of pages of documents. The AG, KIUC, KDOE, Kroger, NAS, DoD, KACA, CAC and MHNA all filed their testimony on March 23, 2004. The Companies filed their rebuttal testimony on April 26, 2004.

On April 28, 2004, a prehearing conference, attended in person or by teleconference by representatives of the AG, KIUC, KDOE, DoD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Companies, took place at the offices of the Commission. During that conference, a number of procedural and substantive issues were discussed, including potential settlement of certain issues. An agreement in principle was reached among all parties to resolve the ESM renewal proceedings. The Companies and Kroger also advised Commission Staff and the other parties that they had reached an agreement on a time-of-day rate pilot program and that a stipulation on that program would be presented at a later date.

On May 4, 2004, the hearing in the rate cases began but was adjourned, before any witnesses were called, for the purpose of exploring the possibility of settlement of the proceedings or stipulation of issues therein. Those discussions were attended in person by representatives of the AG, KIUC, KDOE, DoD, Kroger, KACA, CAC, MHNA, POWER, LFUCG, NAS, the Commission Staff and the Companies. Settlement discussions continued through the afternoon of May 5, 2004, at which time the Commission was advised by all counsel that an agreement in principle had been reached among all parties as to all issues except the revenue requirements for LG&E's electric operations and KU's operations, but that negotiations with NAS were continuing. At that time, the Companies began presenting their witnesses. Cross-examination of those witnesses was waived by all parties except the AG, whose cross-examination was limited to issues related to the revenue requirements for LG&E's electric operations and KU's operations.[22] After the hearing was adjourned for the day on May 5, NAS and KU continued their negotiations and reached an agreement on the applicable tariff to serve NAS and all related issues. Work also continued into the evening on draft settlement and stipulation documents.

At the commencement of the hearing on May 6, the Commission was advised that, subject to finalizing the documents, a settlement had been reached among all parties on all issues

[22] See generally, Transcript of Evidence ("TE") for the hearing dated May 4-6, 2004. Commission Staff also cross-examined some of the Companies' witnesses.

except the electric revenue requirement for LG&E and the revenue requirement for KU, and that all parties, except the AG, were willing to stipulate as to the amount of the Companies' electric revenue requirements.

The Companies then proceeded to put on their remaining proof, and the AG then presented witnesses on the issue of the Companies' electric revenue requirements. The other parties continued to waive cross-examination, and did not offer any evidence. At the end of the day, the hearing was adjourned until May 12, 2004. Following the adjournment, Commission Staff and its counsel, as well as counsel for all parties, remained at the Offices of the Commission to finalize the drafting of the Partial Settlement, Stipulation and Recommendation. During the evening of May 6, 2004, Counsel or representatives of all parties signed the Partial Settlement, Stipulation and Recommendation on a "To Be Recommended" basis.

On May 12, 2004, counsel assembled before the hearing reconvened to execute the Partial Settlement, Stipulation and Recommendation and the ESM Settlement Agreement in final form as "Have Seen and Agreed." Those documents, along with exhibits, were then filed and presented to the Commission. The Companies then moved to have the testimonies and data responses of all intervenors, except that testimony and those data responses of the AG relating to the Companies' electric revenue requirements, withdrawn from the record. With no objection from any party, that motion was sustained by the Commission.[23] The Companies then presented two witnesses to summarize and answer any questions regarding those documents, and Commission Staff conducted cross-examination of one of those witnesses. With no further cross-examination or matters to be addressed, the hearing was then adjourned.

This brief is being filed in compliance with the Commission's Order dated January 14, 2004, and in support of the Companies' Applications, the ESM Settlement Agreement and the

[23] TE, Volume IV, at 14-15.

Partial Settlement, Stipulation and Recommendation. Because the revenue requirements for the electric operations of LG&E and KU remain contested issues, the Companies have briefed the issues associated with the calculation of the electric revenue requirements and the issues raised by the AG in connection therewith. The Companies have also briefed the proposed changes in rate design and noted, where applicable, whether and, if so, how, the terms of the Partial Settlement, Stipulation and Recommendation impact those proposed changes.

Argument

I. FOR YEARS LG&E AND KU HAVE EFFECTIVELY MANAGED RISING COSTS WHILE MAINTAINING EXCELLENT SERVICE, SAFETY AND RELIABILITY.

A. The Companies have increased investments in plant and have faced increased costs of operation.

1. Changes in electric operations since last base rate adjustments

Since the Companies' last rate adjustments in the PBR proceedings, there have been several material changes in the Companies' electric operations of which the Commission should take note. For example, LG&E and KU have increased their net investment in plant for electric operations by over $412 million[24] and $450 million,[25] respectively. In addition to the resulting increase in capital costs, LG&E and KU have also incurred approximately $24 million[26] and $15 million,[27] respectively, in additional depreciation expense associated with those net investments in plant. Keeping their plant properly insured has cost the Companies' more as well - LG&E and KU have each seen an approximately $4 million rise in property insurance costs.[28]

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[24] Staffieri LG&E Direct at 7; Rives LG&E Direct at 3; Thompson LG&E Direct at 11-12; Hermann LG&E Direct at 12.
[25] Staffieri KU Direct at 6; Rives KU Direct at 3; Thompson KU Direct at 11-12; Hermann KU Direct at 13.
[26] Staffieri LG&E Direct at 7.
[27] Staffieri KU Direct at 6-7.
[28] Staffieri LG&E Direct at 7; Staffieri KU Direct at 7.

The Companies have also expended substantial resources for their employees and have incurred other additional operating expenses. LG&E and KU have increased their spending for pensions and other post-retirement expenses by $10 million[29] and $4 million,[30] respectively, principally as a result of the decline in financial market performance. For current employees, the Companies have raised wage rates to stay in line with market rates.[31] In addition, the Companies have experienced increases in their operating expenses for electric operations overall.[32]

Finally, the Companies have made substantial payments to MISO in keeping with their membership therein. The Companies are not currently recovering their MISO Schedule 10 administrative costs, which amounted to approximately $6 million during the test year for the Companies.[33] These are costs the Companies prudently incurred in order to provide service to their customers pursuant to a FERC-approved tariff.

2. Changes in gas operations since last gas base rate adjustment

Since LG&E's last gas rate adjustment in Case No. 2000-080, there have also been several material changes in LG&E's gas operations. LG&E has increased its net investment in plant for gas operations by over $47 million[34] and expended about $94 million in capital since 2000.[35] LG&E has also engaged in an extensive gas main replacement program to enhance safety and reliability.[36] LG&E has incurred approximately $5 million in additional depreciation expense, on a pro forma basis, associated with its net investments in gas plant.[37] And, as referenced above for electric operations, LG&E has expended substantial resources for its gas

[29] Staffieri LG&E Direct at 7.
[30] Staffieri KU Direct at 7.
[31] Staffieri LG&E Direct at 7; Staffieri KU Direct at 7.
[32] Id.
[33] Id.
[34] Staffieri LG&E Direct at 8; Rives LG&E Direct at 3-4.
[35] Hermann LG&E Direct at 12.
[36] Id. at 13.
[37] Staffieri LG&E Direct at 8.

operations to take care of its employees and has also incurred other increased operating expenses.[38]

B. The Companies have successfully managed costs through a number of initiatives.

The Companies have employed a variety of asset management practices and technologies to help control costs in recent years.[39] For example, the Companies have undertaken a system of reliability centered maintenance ("RCM").[40] The traditional maintenance model was a rigid, time-based approach that took no account of whether a particular piece of equipment actually required service at the prescribed interval.[41] RCM, in contrast, allows the Companies to prioritize and allocate their maintenance activities and resources far more efficiently by servicing only those pieces of equipment that actually require service at any given time, consistent with prudent utility practice.[42] The Companies determine which pieces of equipment require service by performance-testing the equipment at regular intervals. As a result, only those pieces of equipment that do not perform adequately receive service.[43]

The Companies also employ distributed control systems ("DCS") as part of their cost-reducing asset management practices.[44] DCS enhances the Companies' operational efficiencies by allowing them to more accurately control and coordinate components of generating units and

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38 Id.
39 Thompson LG&E Direct at 4-7; Hermann LG&E Direct at 5-7; Thompson KU Direct at 4-7; Hermann KU Direct at 5-7.
40 Thompson LG&E Direct at 5-6; Hermann LG&E Direct at 7; Thompson KU Direct at 5-6; Hermann KU Direct at 7.
41 Id.
42 Id.
43 Id.
44 Thompson LG&E Direct at 5; Thompson KU Direct at 5.

other processes and devices integral to power production.[45] DCS also enhances the Companies' real-time diagnostic capabilities.[46]

In addition to asset management techniques and technologies, the Companies have implemented improved work practices to reduce their costs. These improved work practices include (1) using a variable workforce,[47] (2) joint system dispatch and planning,[48] (3) increased employee training and capabilities,[49] and (4) materials outsourcing.[50] Using a variable workforce, or independent contractors, to perform infrequent or periodic maintenance and repairs on generation and transmission assets results in cost savings for the Companies because the work is specialized and often requires equipment that would be uneconomical for the Companies to own and maintain.[51] Joint dispatch and planning has saved the Companies money by reducing redundancies that existed when the Companies were independent entities.[52] The Companies have also improved employee productivity by increasing employee training and capabilities – "multi-skilling" – and sharing the employees' increased expertise among plants across the fleet.[53] Finally, the Companies have reduced in-house inventory and materials handling costs in their gas and electric businesses by using materials outsourcing which means the Companies' suppliers manage, handle and deliver the Companies' need for materials on a timely basis.[54]

The Companies have also controlled costs by employing an array of new technologies and techniques, and using thermal transmission line ratings and telemetry equipment. The

45 Id.
46 Id.
47 Thompson LG&E Direct at 8; Hermann LG&E Direct at 8; Thompson KU Direct at 8; Hermann KU Direct at 8-9.
48 Thompson LG&E Direct at 7; Thompson KU Direct at 7.
49 Thompson LG&E Direct at 7-8; Thompson KU Direct at 7-8.
50 Hermann LG&E Direct at 8-9; Hermann KU Direct at 9.
51 Thompson LG&E Direct at 8; Hermann LG&E Direct at 8; Thompson KU Direct at 8; Hermann KU Direct at 8-9.
52 Thompson LG&E Direct at 7; Thompson KU Direct at 7.
53 Thompson LG&E Direct at 7-8; Thompson KU Direct at 7-8.
54 Hermann LG&E Direct at 8-9; Hermann KU Direct at 9.

Companies' gas and electric operations will soon all use Geospatial Enterprise Management Integration Network Initiative ("GEMINI"), a system that integrates a work management system, outage management system, geographic information system ("GIS") and graphical work design system.[55] By streamlining data access and management, GEMINI will allow the Companies to achieve the efficiencies of an optimized workforce by better tracking service installation or restoration status, improving work order scheduling, tracking outages, and using GIS's geographical data overlay to more reliably and effectively locate the Companies' distribution facilities.[56]

The Companies have completed the installation of MAXIMO on the generation side and Energy Management Systems ("EMS") on the transmission side. MAXIMO also supports the Companies' ability to implement consistent maintenance practices throughout their distribution operations by identifying, analyzing and maintaining physical assets such as substations and gas compressor stations.[57] By monitoring and analyzing equipment testing data, MAXIMO can create reliability-centered maintenance schedules that optimize equipment usage, materials inventories and maintenance workers' time.[58] EMS, likewise, provides real-time diagnostic capabilities by continuously monitoring and storing various transmission data.[59] Both of these technologies result in savings for the Companies.

Integrated Voice Response Unit ("IVRU") and Service Makes It Look Easy ("SMILE") are technologies the Companies employ in conjunction with their call center integration and customer service improvement efforts, which have also helped hold down the Companies' costs.

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[55] Hermann LG&E Direct at 9-10; Hermann KU Direct at 9-10.
[56] Id.
[57] Thompson LG&E Direct at 6-7; Hermann LG&E Direct at 9-10; Thompson KU Direct at 6; Hermann KU Direct at 9-11.
[58] Id.
[59] Thompson LG&E Direct at 6-7; Thompson KU Direct at 6-7.

The Companies implemented the IVRU in late 1999 to handle larger volumes of calls and route calls more effectively to the call center representatives best able to assist the callers, enabling the same number of operators to assist a larger number of customers.[60] SMILE facilitates customer service by creating a single, common data presentation for the operator, drawing a customer's information from all the Companies' databases.[61] SMILE's single presentation speeds operator training and decreases the time an operator requires to help each customer, which results in savings for the Companies.[62] Both IVRU and SMILE helped make it possible for the Companies to integrate their three customer service call facilities, which now function as would a single location, allowing easy, cost-saving transfer of customers to precisely the right operators.[63]

Finally, the Companies' use of thermal transmission line ratings and telemetry equipment has also improved efficiencies. The Companies' use of thermal transmission line ratings has measurably increased the Companies' transmission assets' productivity, as indicated by the significant decrease in the number of Transmission Line Loading Relief directives ("TLRs") the Companies' regional transmission grid operator has called since the Companies adopted thermal transmission line ratings.[64] The Companies' increased use of telemetry equipment has allowed the Companies' dispatch centers to operate and monitor substation equipment remotely and in real-time, giving rise to workforce efficiencies and enhanced system reliability.[65]

C. <u>The Companies' progressive cost-management initiatives have been successful while maintaining excellent service quality, reliability and safety.</u>

What is perhaps most impressive about the Companies' cost-control efforts is that they have not compromised the Companies' service, reliability or safety.

[60] Hermann LG&E Direct at 9, 10-11; Hermann KU Direct at 9, 11-12.
[61] Hermann LG&E Direct at 9, 11-12; Hermann KU Direct at 9, 12.
[62] Hermann LG&E Direct at 11-12; Hermann KU Direct at 12.
[63] Id.
[64] Thompson LG&E Direct at 7; Thompson KU Direct at 7.
[65] Id.

1. Customer Service

In 2002 and 2003, J.D. Power & Associates ranked the Companies first in the nation among investor-owned utilities in overall satisfaction among residential electric customers.[66] The Companies also ranked highest nationwide for customer satisfaction in J.D. Power's 2003 survey of midsize business customers.[67] In addition, LG&E ranked second overall for customer satisfaction among gas utilities in the Midwest in J.D. Power's survey of 55 of the largest local gas distributors nationwide.[68] And, as noted earlier, the Companies have invested in new technology for their call centers so that customers can be assisted more effectively.

2. Reliability

The Companies have also made substantial investments in their utility infrastructure, including transmission and distribution systems and electric generation to ensure ongoing system reliability.[69] Specifically, the Companies have, among other things, installed new distributed control systems, rebuilt cooling towers, replaced coal handling equipment and turbine blading, and refurbished boilers, precipitators and scrubbers across the fleet.[70] The Companies have also added six new gas-fired combustion turbines for increased system capacity, particularly during peak periods. These units, jointly owned by the Companies, are a product of the Companies' joint planning capabilities, which allow for the most efficient procurement and use of capacity system-wide.

The Companies' electric generation system reliability compares quite favorably with the rest of the industry and further demonstrates that the Companies have not sacrificed reliability to

[66] Staffieri LG&E Direct at 9; Hermann LG&E Direct at 16-18; Staffieri KU Direct at 8; Hermann KU Direct at 15-17.
[67] Hermann LG&E Direct at 16; Hermann KU Direct at 15-16.
[68] Hermann LG&E Direct at 17.
[69] Staffieri LG&E Direct at 8; Thompson LG&E Direct at 11-13; Staffieri KU Direct at 7; Thompson KU Direct at 10-12.
[70] Thompson LG&E Direct at 11; Thompson KU Direct at 11.

control costs. The Companies' combined system Equivalent Forced Outage Rate ("EFOR"), a measure the industry commonly uses to gauge the reliability of coal-fired generating units, is quite low and ranks favorably against the rest of the industry.[71] In fact, based on a comparison to all coal-fired baseload units nationwide, the Companies' overall system EFOR (the capacity weighted average EFOR of all coal-fired generating units) consistently achieves top quartile performance.[72] Similarly, the Companies' transmission system consistently surpasses performance targets on an annual basis, where the Companies set those targets by using a "duration of service interruption" tracking measure.[73]

3. Safety

Finally, the Companies' efforts to manage costs have not compromised their safety performance. Indeed, the Companies have a long-standing "No Compromise" policy, which states that it is unacceptable for anyone to work in an unsafe manner.[74] The Companies support this policy with random field audits, safety tailgates and quarterly safety meetings.[75] And the "No Compromise" policy works, as evidenced by still-declining OSHA recordable incident rates that are significantly below the national average.[76] Indeed, the Companies' safety program exceeds the safety mandates of OSHA and the National Electric Safety Code, and has won numerous Governor's Safety and Health Awards.[77]

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[71] Thompson LG&E Direct at 9-10; Thompson KU Direct at 9-10.
[72] Id.
[73] Thompson LG&E Direct at 12; Thompson KU Direct at 11-12.
[74] Hermann LG&E Direct at 14-15; Hermann KU Direct at 13-14.
[75] Id.
[76] Id.
[77] Id.

The Companies' concern for safety extends beyond its employees to its contractors. The Companies' contractors have a safety rating that is significantly better than the most recent national benchmark.[78]

It is clear, therefore, that the Companies have been able to maintain, and even improve upon, their success in customer service, reliability and safety even in the face of a number of cost-control measures.

II. ALL PRUDENT MEANS OF REDUCING COSTS INTERNALLY HAVE BEEN EXHAUSTED AND A REASONABLE RATE ADJUSTMENT IS NOW NECESSARY.

As noted above, the Companies have long histories of operating efficiently. That efficiency, however, can no longer prevent the need for a base rate increase. When considering the possibility of seeking a base rate increase, the Companies studied whether further efficiencies could be achieved to allow for the opportunity to earn a fair rate of return, and determined that no such efficiencies were possible without compromising the level of service to their customers.[79] Mr. Staffieri testified that the Companies compared their operations to those of 140 other utilities across the country, and specifically looked at five categories of operating expenses: retail, administrative and general, distribution, transmission, and generation.[80] That comparative analysis revealed that the Companies were in the top quartile in each category and, in fact, that KU and LG&E were the only utilities in the top quartile in every category.[81] Those results, and the Companies' own experience and knowledge, revealed that the Companies were already

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[78] Thompson LG&E Direct at 13; Thompson KU Direct at 13.
[79] TE, Volume II, at 38-39.
[80] Id. at 38.
[81] Id. at 38-39.

operating in a highly efficient manner and that further significant efficiencies could not be achieved.[82]

It is clear that the Companies are not presently earning a fair rate of return. The results of LG&E's annual ESM for 2002, for example, show that it earned a return on equity of 7.56% and a return on capital of 5.61% for its electric operations, well below the 11.5% return on common equity and the overall cost of capital of 8.47% approved by the Commission in Case No. 98-426.[83] For the twelve months ended September 30, 2003, the return on equity further declined to 5.96% and the return on capital has declined to 4.58% for electric operations.[84] In 2002, LG&E earned a return on equity of 7.43% and a return on capital of 5.18% for its gas operations, also below Commission-approved returns in Case No. 2000-080 of 11.25% for return on equity and 8.21% return on capital.[85] For the twelve months ended September 30, 2003, the return declined to 3.92% and the return on capital has declined to 3.60% for gas operations.[86] Likewise, KU's annual ESM for 2002 shows that it earned a return on equity of 7.90% and a return on capital of 6.16%, well below the 11.5% return on common equity and the overall cost of capital of 9.58% approved by the Commission in Case No. 98-474.[87] And, for the twelve months ended September 30, 2003, the return on equity declined to 6.22% and the return on capital has declined to 4.63% for electric operations.[88]

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[82] Id; Thompson KU Direct at 3; Thompson LG&E Direct at 3; Hermann KU Direct at 3-4; Hermann LG&E Direct at 3-4.
[83] Rives LG&E Direct at 4; *In the Matter of: Application of Louisville Gas and Electric Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-426, Order dated June 1, 2000.
[84] Rives LG&E Direct at 4.
[85] Id. at 4; *In the Matter of: Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order dated September 27, 2000.
[86] Rives LG&E Direct at 4.
[87] Rives KU Direct at 3; *In the Matter of: Application of Kentucky Utilities Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-474, Order dated June 1, 2000.
[88] Rives KU Direct at 3-4.

While it is certainly not in the public interest to have financially weakened utilities,[89] it is also a fundamental legal requirement of "fair, just and reasonable rates" that they be sufficient to "enable the utilit[ies] to operate successfully, to maintain [their] financial integrity, to attract capital and to compensate [their] investors for the risks assumed...."[90] The Commission should allow the Companies at least the stipulated rate increases because they are necessary to preserve the Companies' financial integrity, to compensate their investors for the risks assumed, and to allow the Companies to continue to operate successfully by continuing to provide safe, reliable utility service and quality customer service.[91]

III. LG&E'S AND KU'S CALCULATION OF THEIR RATE BASES IS REASONABLE AND SHOULD BE APPROVED.

A. <u>The Companies' calculated rate bases are reasonable.</u>

LG&E determined that its test-year net original cost of rate base for electric operations is $1,675,374,829.[92] KU determined that its test-year net original jurisdictional rate base is $1,549,420,616.[93]

B. <u>The Commission should not use rate base to determine revenue requirements.</u>

Revenue requirements for LG&E's combined electric and gas operations and KU's electric operations have historically been based on capitalization rather than on rate base. Similarly, the Commission historically has determined the revenue requirements for another combined gas and electric utility, The Union Light Heat and Power Company, using capitalization rather than rate base. Absent sufficient justification, the Commission has

[89] Rives LG&E Direct at 3; Rives KU Direct at 3.
[90] *Commonwealth ex rel. Stephens v. South Central Bell Telephone Co.*, Ky., 545 S.W.2d 927, 930-31 (1976) (citing *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).
[91] Staffieri LG&E Direct at 9-10; Hermann LG&E Direct at 5; Rives LG&E Direct at 3; Staffieri KU Direct at 9; Hermann KU Direct at 5; Rives KU at 3.
[92] Rives LG&E Direct at Exhibit 3, p. 1 of 2.
[93] Rives KU Direct at Exhibit 3, p. 1 of 1.

previously stated that it will continue to determine revenue requirements for LG&E using capitalization rather than rate base.

In this proceeding, the AG has not provided any evidence to justify the use of the rate base approach to determine revenue requirements other than stating that the Commission should use the lower of rate base or capitalization (which in this case happens to be capitalization) in order to determine the Companies' revenue requirements. The Companies strongly disagree with this results-oriented recommendation and recommend that the Commission, consistent with precedent, set their returns in these proceedings based on capitalization.[94] Capitalization reasonably represents the amount of investment supporting the Companies' utility operations and has been used consistently by the Commission.[95] The record in these proceedings provides no valid reason or compelling evidence to deviate from the well-established Commission precedent.[96]

The AG also argues that the Companies have not presented an adjusted original cost rate base for the purpose of determining the appropriate return on capitalization. As required by Section 10(6)(i) of 807 KAR 5:001, the Companies presented a reconciliation of their respective rate bases and capitalization; however, the regulation does not require the Companies to present an adjusted original cost rate base.[97] Nonetheless, in response to the Commission's discovery requests, KU presented its adjusted original cost rate base in response to PSC 3-38, and LG&E presented its adjusted original cost rate base in response to PSC 3-39. No party to this

[94] Rives LG&E and KU Rebuttal at 4.
[95] Id.
[96] Id.
[97] Id. at 5.

proceeding challenged the Companies' reconciliations. The Commission did question LG&E and KU about the reconciliations and sought clarifications of the information provided.[98]

The detailed inquiry into the rate base calculation asserted by the AG is not necessary in this case because the Companies are seeking a return on capitalization consistent with the Commission's historical method of regulation. As the Commission previously stated, "[t]he capitalization of the utility is a better measure of the real cost of providing service since it is the cost of debt and equity that is reflected in the financial statements of the utility. To impute the operating income requirements based on an inflated rate base in effect establishes a cost of doing business that is non-existent to the utility."[99] Indeed, the Kentucky Supreme Court observed that under Kentucky regulation a calculation based on rate base is simply "an after the fact unnecessary exercise in arithmetic."[100]

C. <u>The calculation of the reproduction cost rate base.</u>

LG&E determined that its estimated net reproduction cost rate base as of September 30, 2003 for electric operations was $3,036,157,656.[101] KU's reproduction cost of its Kentucky jurisdictional plant as of September 30, 2003 was estimated to be $2,752,873,919.[102] The AG did not challenge these calculations.

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[98] *See* LG&E's response to Commission's March 1, 2004 Order, Item 39, and KU's response to Commission's March 1, 2004 Order, Item 38.
[99] *In the Matter of: Application of Louisville Gas and Electric Company to Adjust its Gas Rates and to Increase its Charges for Disconnecting Service, Reconnecting Service and Returning Checks*, Case No. 2000-080, Order dated September 27, 2000, p. 11.
[100] *Public Service Commission v. Continental Telephone Co.*, Ky., 692 S.W.2d 794, 798 (1985).
[101] Rives LG&E Direct at Exhibit 4, p. 1.
[102] Rives KU Direct at Exhibit 4, p. 1.

IV. THE COMPANIES' ADJUSTED ELECTRIC CAPITALIZATIONS ARE REASONABLE

A. <u>LG&E's and KU's adjusted electric capitalizations are reasonable.</u>

1. LG&E's adjusted electric capitalization is reasonable

LG&E's Rives Exhibit 2 shows the calculation of LG&E's adjusted capitalization as of September 30, 2003 as well as the weighted average cost of capital to apply to the adjusted capitalization. The direct testimony of Mr. Rives shows the capitalization for LG&E's electric operations is $1,485,701,357 and explains the adjustments thereto.[103] Included in the calculation of the total electric capitalization are six adjustments: the removal of 25 percent of inventories related to Trimble County; the removal of LG&E's investment in Ohio Valley Electric Company; the addition of the Job Development Tax Credit; the removal of the impact of the repairs to the combustion turbines at Units 6 and 7 at the E. W. Brown Generation Station; the removal of the effect of LG&E's accounting entry for its minimum pension liability ("MPL") adjustment to Other Comprehensive Income; and the removal of the costs associated with LG&E's 2001 Environmental Surcharge Plan. With the exception of the MPL adjustment, LG&E's other five adjustments are allocated on a pro rata basis to all components of capital.

2. KU's adjusted electric capitalization is reasonable.

KU's Rives Exhibit 2 shows the calculation of KU's adjusted capitalization as of September 30, 2003 as well as the weighted average cost of capital to apply to the adjusted capitalization. The direct testimony of Mr. Rives shows the capitalization for KU's electric operations is $1,654,555,027 and the Kentucky adjusted jurisdictional capitalization is $1,318,124,983 and explains the adjustments thereto.[104] Included in the calculation of the total

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[103] Rives LG&E Direct at 21-26 and Exhibit 2, p. 1 of 2.
[104] Rives KU Direct at 18-22 and Exhibit 2, p. 1 of 1.

electric capitalization are seven adjustments: the first three adjustments remove undistributed subsidiary earnings, KU's equity investment in Electric Energy Inc., and KU's investment in Ohio Valley Electric Corporation and other investments consistent with the adjustments approved in the Commission's Order in Case No. 90-158; the remaining four adjustments remove the impact of the repairs to the combustion turbines at Units 6 and 7 at the E. W. Brown Generation Station, remove the capitalization related to the impending retirement of Green River Units 1 and 2, remove the cost associated with KU's Post-1994 Environmental Surcharge Plan and provide an addition to common equity to reverse the impact of KU's MPL adjustment to Other Comprehensive Income. With the exception of the MPL adjustment and the adjustment to remove undistributed subsidiary earnings, KU's other adjustments are allocated on a pro rata basis to all components of capital.

As KU explained in response to PSC Item 2-15(b)(4), based upon additional analysis related to the Green River retirement and a review of FERC guidelines related to partial retirements, KU determined that it was not appropriate to reduce capitalization by the units to be retired. The retirement was recorded through a reduction in Account 101, Plant in Service, and a corresponding charge to Account 108, Accumulated Depreciation. Since this entry had no effect on the plant accounts in total, no adjustment is needed to rate base or capital.

The AG witnesses, Dr. Weaver and Messrs. Henkes and Majoros, either agree with or take no exception to the Companies' capitalization amounts and adjustments, except for the MPL adjustment.[105]

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[105] Weaver Direct at 75; Direct Electric Testimony and Exhibits of Robert J. Henkes of March 23, 2004 (Case No. 2003-00433) ("Henkes Electric Direct") at 8-14; and Michael J. Majoros, Jr. Revenue Requirements Testimony of March 23, 2004 (Case No. 2003-00434) ("Majoros Revenue Requirements Direct") at 3-7.

B. The Companies' MPL adjustments to common equity are reasonable; the AG's recommendation to reject the MPL adjustment is not reasonable.

The direct testimony of Mr. Rives explains in detail the Companies' MPL adjustment and why the adjustment is necessary to avoid unfair regulatory policy by reducing equity today for a potential never-to-be-realized loss that has not and may never be recorded on the income statement.[106] Such treatment of MPL has been expressly recognized by the FERC. Specifically, on March 29, 2004, the FERC issued an opinion letter in Docket No. AI04-2-000 providing that jurisdictional public utilities shall recognize a regulatory asset for their minimum pension liability otherwise chargeable to accumulated other comprehensive income related to its costs-based rate regulated business segments. A copy of that opinion letter was filed in these proceedings on April 15, 2004 in the Companies' Supplemental Response to data request PSC 3-9(b), and is also attached as SBR Rebuttal Exhibit 1. The Companies have made adjustments in their accounting records consistent with the FERC mandate effective March 2004, and will reflect those adjustments in their next quarterly filings with the Commission and FERC.[107]

The AG contends that the Companies' MPL adjustments should be rejected for three reasons. First, the AG asserts that the MPL adjustment should be rejected because the Companies have already made write-downs to their common equity balance, and proposed reversals of equity write-downs were rejected in Case Nos. 98-426 and 98-474.[108] This contention should be rejected. The write-downs in Case Nos. 98-426 and 98-474 reflected the shareholder portion of costs associated with the merger of KU and LG&E in the test periods. Consequently, the Companies' respective retained earnings were reduced which lowered the

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[106] Rives LG&E Direct at 22-25; Rives KU Direct at 19-22.

[107] LG&E and KU Rives Rebuttal at 6-7.

[108] Henkes Electric Direct at 11; Direct Gas Testimony and Exhibits of Robert J. Henkes of March 23, 2004 (Case No. 2003-00433) ("Henkes Gas Direct") at 10-11; Majoros Revenue Requirements Direct at 16-17.

Companies' common equity component of their capitalizations. In those proceedings, the Companies proposed a reversal of this write-off by adjusting such common equity components because it was a non-recurring item and for reasons related to the regulatory recognition of the merger. In addition to other reasons related to the ratemaking recognition of the shareholders' portion of the merger savings, the Commission rejected the proposed write-down reversals after determining that write-offs were permanent and continuous in nature and thus would have a recurring impact on the Companies' future equity components. In sharp contrast, in these proceedings, the MPL equity write-down is not permanent and, in fact, is likely to be reversed (*i.e.* the Companies will likely recover in rates any increased pension expense in the future, if necessary).[109] The AG's witness also acknowledged under cross-examination at the hearing that, unlike the write-downs in Case Nos. 98-426 and 98-474, the write-downs in these rate proceedings would not continue to affect the Companies' capitalizations in the future as interest rates and the fair market value of the pension assets changed over time.[110] Accordingly, the analysis of the capital structure adjustments by the Commission in Case Nos. 98-426 and 98-474 has no bearing on the need for and analysis of the MPL adjustments in these proceedings.

In addition, the AG contends that the Companies' proposed MPL adjustment is inconsistent with SFAS No. 71.[111] However, as discussed earlier, the FERC resolved this issue in its March 29, 2004 opinion letter, as follows:

> Further, the minimum pension liability, as well as, any related regulatory asset is not amortized over future periods. At each measurement date, the entry recorded for the previous measurement date is reversed and the computation redone. A new minimum pension liability and related regulatory asset would be recognized, if required, at the new measurement date.

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109 LG&E Rives Direct at 22-25; KU Rives Direct at 19-22.
110 TE, Volume III, at 118-124.
111 Henkes Gas Direct at 11; Henkes Electric Direct at 11; Majoros Revenue Requirements Direct at 5-6.

Finally, the AG contends that "the establishment of a regulatory asset pursuant to SFAS 71 may give rise to a presumption that the underlying costs are recoverable from ratepayers and preclude a prudence review of these costs in the future."[112] This statement is based on mere speculation since the Companies have made no claim for such treatment. The FERC opinion letter of March 29, 2004, expressly provides that the MPL and the related regulatory asset are not amortized over future periods, but are adjusted at each subsequent measurement date. The FERC opinion letter also expressly states that the accounting for the MPL "does not limit the Commission from reviewing the reasonableness of the elements of pension expense included in future rate proceedings...."[113] The AG's witness conceded this point under cross-examination.[114] For all of those reasons, the AG's position on the Companies' MPL adjustments should be rejected, and those adjustments should be allowed.

V. THE TEST YEAR REVENUES AND EXPENSES FOR LG&E AND KU SHOULD BE ADJUSTED FOR KNOWN AND MEASURABLE CHANGES TO REFLECT MORE CURRENT OPERATING CONDITIONS.

A. Pro forma adjustments for known and measurable changes by both companies.

The Companies have both proposed a number of reasonable pro forma adjustments to revenues and expenses for known and measurable changes. For the electric operations, as reflected in the twelve-month period ended September 30, 2003, the Companies have made adjustments which eliminate the effect of unbilled revenues, remove the impact of items included in other rate mechanisms, and annualize year-end facts and circumstances. In addition, the Companies propose to adjust for other known and measurable changes to revenues and expenses,

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112 Henkes Electric Direct at 12; Henkes Gas Direct at 11; *see also* Majoros Revenue Requirements Direct at 5-6.
113 LG&E and KU Rives Rebuttal at Exhibit 1, p. 3 of 3.
114 TE, Volume III, at 125-126.

other excludable unusual, non-recurring or out-of-test period items in the test year, and Federal and state income tax expenses for these pro forma adjustments.

1. Adjustment to eliminate the effect of unbilled revenues

Consistent with the Commission's rulings in LG&E's last two base rate cases, Case No. 2000-080 and Case No. 90-158, unbilled revenues were removed from the Companies' test-year operating revenues.[115] For LG&E's electric operations, $1,867,000 of unbilled revenues were removed from the test-year operating results.[116] For KU's electric operations, $675,000 of unbilled revenues were removed from the test-year operating results.[117] This adjustment is consistent with the adjustment to eliminate unbilled revenues for the gas business.[118]

The AG's witness, Robert J. Henkes, proposed to remove unbilled revenues from test-year operating results, consistent with the Companies' proposal, but oddly recommended attributing expenses to those unbilled revenues.[119] Mr. Seelye's rebuttal testimony noted that "Mr. Henkes is performing a flip-flop of sorts on this issue" when he made the following observation:

> Mr. Henkes submitted testimony on behalf of the AG in LG&E's last base gas rate case (Case No. 2000-080). Although several data requests were submitted by the AG in Case No. 2000-080 concerning unbilled revenues, Mr. Henkes did not propose to make an expense adjustment to reflect the elimination of unbilled revenues in that proceeding. Yet, in the current proceeding, rather than being guided by sound ratemaking principles, Mr. Henkes has developed a creative way to penalize the Companies - he applies the operating ratios used in the Companies' year-end adjustments

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[115] *In the Matter of: Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order dated September 27, 2000; *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 90-158, Order dated December 21, 1990.
[116] Seelye LG&E Direct at 51.
[117] Seelye KU Direct at 23.
[118] Seelye LG&E Direct at 51.
[119] Henkes Gas Direct at 27-29; Henkes Electric Direct at 30-32.

> to every revenue adjustment in sight, regardless of whether it makes any sense to perform such an adjustment.[120]

The AG's recommendation is also contrary to prior Commission practice. The AG's application of an operating ratio to revenues that include FAC, ECR, DSM and other components of revenue that have been removed from test-year operating results is unreasonable because its fails to consider that the pro forma adjustments made in the rate case already account for any mismatch in revenues and expenses that might otherwise occur.[121] Mr. Henkes' testimony contains no quantitative analysis to support the validity of the application of the operating ratio in the year-end adjustment to calculate the expenses associated with the unbilled revenues.[122] Under cross-examination, Mr. Henkes admitted that his only support was his assumption that the operating ratio used in the year-end adjustment was applicable for calculating the expenses associated with the unbilled revenues.[123] As Mr. Seelye explained, measuring the additional expenses related to serving more customers is not a simple exercise because not all expenses change in direct proportion to increases in the number of customers.[124] For this reason, certain expenses are removed from "net revenues" in the computation of the operating ratio (*e.g.*, the Commission has traditionally required the removal of wages and salaries, pensions and benefits, and regulatory commission expenses in determining net revenue).[125]

The Commission should accept the Companies' proposed unbilled revenue adjustment and reject the recommendation of the AG to impute a hypothetical expense amount associated with the unbilled revenues.

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[120] Rebuttal Testimony of William Steven Seelye of April 26, 2004 (Case No. 2003-00433 and 2003-00434) ("Seelye LG&E and KU Rebuttal") at 22-23.
[121] Seelye LG&E and KU Rebuttal at 23.
[122] TE, Volume III, at 129.
[123] TE, Volume III, at 130.
[124] Seelye LG&E and KU Rebuttal at 25.
[125] Id.

2. Adjustment to account for the mismatch in fuel cost expenses and revenues

The Companies have also proposed an adjustment to account for the timing mismatch in fuel cost expenses and revenues under the Fuel Adjustment Clause ("FAC") for the twelve months ended September 30, 2003. Consistent with past Commission practice, the mismatch between fuel costs and fuel cost recovery through the Companies' FACs have been eliminated.[126] These over- or under-recoveries were taken directly from LG&E's and KU's monthly FAC filings.[127]

In PSC data request to KU, Item 2-15(a), the Commission Staff asked KU to reconcile a number on Rives Exhibit 1, Schedule 1.1 with comparable information presented in KU's FAC monthly filings. In its response, KU acknowledged that the correct number appeared on the revised FAC filing and not in KU Rives Exhibit 1. The response demonstrates that the corresponding revision was equal to $3,170,000. The change increases KU's revenue deficiency from the amount of $58.3 million to $61.4 million.

The AG's witnesses did not take exception to this adjustment.

3. Adjustment to base rates and FAC to reflect a full year of the FAC and ECR roll-in

The Companies have also proposed adjustments to reflect the rolled-in level of base rates and FAC and ECR billings for a full year. These adjustments were directed by the Commission's April 23, 2003 Orders in Case Nos. 2002-00433 and 2002-00434 and the Commission's October 22, 2002 Orders in Case Nos. 2002-00193 and 2003-0068.[128]

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[126] Rives LG&E Direct at 8; Rives KU Direct at 7; Seelye LG&E Direct at 51; Seelye KU Direct at 24.

[127] Seelye LG&E Direct at 51; Seelye KU Direct at 24.

[128] *In the Matter of: An Examination by the Commission of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from November 1, 2000 to October 31, 2002*, Case No. 2002-00433, Order dated April 23, 2003; *In the Matter of: An Examination by the Commission of the Application of the Fuel Adjustment Clause of Louisville Gas and Electric Company from November 1, 2000 to October 31, 2002*, Case No. 2002-00434, Order dated April 23, 2003; *In the Matter of: An Examination by the Commission of the Environmental Surcharge*

The AG's witnesses did not take exception to this adjustment.

4. Adjustment to eliminate environmental surcharge revenues and expenses

Consistent with the Commission's practice of eliminating the revenues and expenses associated with full-recovery cost trackers, an adjustment has been proposed to eliminate $11,228,429 of Environmental Cost Recovery ("ECR") revenues and $1,766,344 in ECR costs for LG&E and $25,039,979 of ECR revenues and $248,468 in ECR costs for KU.[129] The ECR surcharge provides for full recovery of environmental costs that qualify for the surcharge and contain a mechanism to true up actual revenues to allowed ECR revenues under the surcharge.

LG&E's adjustment to revenues of $11,228,429 includes all ECR billings during the test year (including ECR recoveries for the 1995 Plan and for the post-1995 Plan).[130] The adjustment to expenses of $1,766,344 includes operating expenses recovered under the ECR during the test year for compliance costs that will continue to be recovered through the surcharge (*i.e.*, operating expenses relating to the post-1995 Plan).[131] Because LG&E is proposing to eliminate the 1995 Plan from its monthly Environmental Surcharge filings on a going-forward basis, only the operating expenses associated with the post-1995 Plan are eliminated in this adjustment.[132] However, all ECR revenues collected in the test year are eliminated because failure to do so would overstate LG&E's adjusted operating revenues by that portion of ECR revenues not

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Mechanism of Louisville Gas and Electric Company for the Six-Month Billing Periods Ending April 30, 2000, October 31, 2000, October 31, 2001, and April 30, 2002 and for the Two-Year Billing Period Ending April 30, 2001, Case No. 2002-00193, Order dated October 22, 2002; *In the Matter of: An Examination by the Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company for the Six-Month Billing Periods Ending January 31, 2001, July 31, 2001, January 31, 2002, and January 31, 2003 and for the Two-Year Billing Period Ending July 31, 2000 and July 31, 2002*, Case No. 2003-0068, Order dated October 22, 2002.

[129] Id. at 52; Seelye KU Direct at 24.

[130] Seelye LG&E Direct at 52.

[131] Id.

[132] Id.

eliminated.[133] LG&E proposes to recover the revenue requirements on any remaining rate base in the 1995 Plan through base rates, and proposes to recover revenue requirements of remaining rate base in the post-1995 Plan through the monthly Environmental Surcharge filings.[134] LG&E's capitalization includes an adjustment to eliminate the ECR rate base for the post 1995 Plan and does not include an adjustment for the ECR rate base for the 1995 Plan.[135]

KU's adjustment to revenues of $25,039,979 includes all ECR billings during the test year (including ECR recoveries for the 1994 Plan and for the post-1994 Plan).[136] The adjustment to expenses of $248,468 includes operating expenses recovered under the ECR during the test year for compliance costs that will continue to be recovered through the surcharge (*i.e.*, operating expenses relating to the post-1994 Plan).[137] Because KU is proposing to eliminate the 1994 Plan from its monthly Environmental Surcharge filings on a going-forward basis, only the operating expenses associated with the post-1994 Plan are eliminated in this adjustment.[138] However, all ECR revenues collected in the test year are eliminated because failure to do so would overstate KU's adjusted operating revenues by that portion of ECR revenues not eliminated.[139] KU proposes to recover the revenue requirements on any remaining rate base in the 1994 Plan through base rates, and proposes to recover revenue requirements of remaining rate base in the post-1994 Plan through the monthly Environmental Surcharge filings.[140] KU's capitalization includes an adjustment to eliminate the ECR rate base for the post-1994 Plan and does not include an adjustment for the ECR rate base for the 1994 Plan.[141]

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133 Id.
134 Id.
135 Id.
136 Seelye KU Direct at 24.
137 Id. at 24-25.
138 Id. at 25.
139 Id.
140 Id.
141 Id.

As explained by Mr. Seelye in his rebuttal testimony, there are several reasons why it is preferable to include the costs associated with the original ECR plans and revenue requirements in this proceeding and discontinue the recovery of these costs through the environmental surcharge:

> First, the projects included in the original plans are essentially complete. Second, the methodology proposed by the Company allows us to terminate the surcharges for KU's 1994 Plan and LG&E's 1995 Plan - to put them to bed, so to speak. Third, including these costs in the revenue requirements is the most straightforward way to incorporate these costs in base rate revenue requirements. The advantage of including these costs in revenue requirements for the rate case and terminating the environmental surcharge on these costs is that they will be rolled into base rates just like any other cost, thus eliminating the need to continue showing an ECR on these amounts for years to come. In other words, the methodology proposed by KU and LG&E does not perpetuate an environmental surcharge on the original environmental compliance plans.[142]

Mr. Seelye's rebuttal testimony also describes alternative approaches that would permit these costs to continue to be recovered through the environmental surcharge, but provide the Companies the opportunity to earn a fair, just and reasonable return on their investments.[143] While either of these alternatives would allow the Companies the opportunity to recover the original plan costs, including a fair, just and reasonable return on their investments, the Companies preference is to terminate the ECR surcharge for the original compliance plans.

The parties to the Partial Settlement, Stipulation and Recommendation, including the AG, agreed in Section 3.4 thereof that all costs associated with KU's 1994 Plan and LG&E's 1995 Plan should be recovered in the Companies' base rates and removed from the Companies' monthly environmental surcharge filings. Details of the recovery are set forth in Exhibit 3 to the Partial Settlement, Stipulation and Recommendation.

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142 Seelye LG&E and KU Rebuttal at 34.
143 Seelye LG&E and KU Rebuttal at 34-36.

5. Adjustment for off-system sales revenue for the ECR calculation

In the determination of their ECR surcharges, a portion of the Companies' environmental compliance costs recovered through the surcharge is allocated to off-system sales. However, by including off-system revenues in test-year operating results, off-system revenues are credited to jurisdictional customers. This results in an overstatement of margins from off-system sales and a mismatch of the revenues and expenses relating to the off-system sales portion of the allocated environmental surcharge monthly revenue requirement.[144] These adjustments are made in accordance with the methodology approved by the Commission in its June 1, 2000 Orders in Case Nos. 98-426 and 98-474.[145] It is also consistent with the Commission's determinations in Case Nos. 94-332 and 95-060 that the Companies should assign eligible environmental compliance costs attributable to off-system sales that are otherwise eligible for environmental surcharge recovery.[146]

In a data request, the Companies were asked why they excluded intercompany sales revenues in the calculation of this adjustment. The Companies responded that while the adjustment was calculated based on prior Commission practice, the Companies believed that intercompany revenues should not be excluded from the adjustment. The Companies filed a response demonstrating the impact of excluding intercompany sales revenues in the calculation

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[144] Seelye LG&E Direct at 53; Seelye KU Direct at 25.

[145] *In the Matter of: Application of Louisville Gas and Electric Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-426, Order dated June 1, 2000; *In the Matter of: Application of Kentucky Utilities Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-474, Order dated June 1, 2000.

[146] *In the Matter of: Application of Louisville Gas and Electric Company for Approval of Compliance Plan and to Assess a Surcharge Pursuant to KRS 278.183 to Recover Costs of Compliance with Environmental Regulations for Coal Combustion Wastes and By-Products*, Case No. 94-332, Order dated April 6, 1995; *An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Kentucky Utilities Company as Billed From August 1, 1994 to January 31, 1995*, Case No. 95-060, Order dated August 22, 1995.

of Rives Exhibit 1, Schedule 1.05 for each Company. The revision increased LG&E's revenue deficiency by $995,894 and KU's revenue deficiency by $1,490,411.[147]

The AG did not contest this adjustment.

If the Commission does not accept the recommended and stipulated revenue requirement increase for LG&E's and KU's electric operations, the Commission should accept the Companies' adjustment as revised to exclude intercompany sales revenues.

6. Adjustment to eliminate electric brokered sales revenues and expenses

The adjustment to eliminate electric brokered sales revenues and expenses was directed by the Commission's January 7, 2000 Orders in Case Nos. 98-426 and 98-474.[148] Brokered transactions do not utilize company generation or transmission assets; accordingly, the related revenue and expenses are eliminated in determining base rates.

The AG's witnesses did not take exception to this adjustment.

7. Adjustment to eliminate electric ESM revenues collected

This adjustment is necessary to eliminate the impact of the ESM revenues collected during the test period and not included in Rate Refund Account 449. The impact of rate mechanisms like the ESM should be removed from the test year revenues when assessing the adequacy of base rates.[149]

The AG's witnesses did not take exception to this adjustment.

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[147] LG&E Supplemental Response to KIUC 1-69; KU Supplemental Response to KIUC 1-54.
[148] *In the Matter of: Application of Louisville Gas and Electric Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-426, Order dated January 7, 2000; *In the Matter of: Application of Kentucky Utilities Company for Approval of An Alternative Method of Regulation of Its Rates and Services*, Case No. 98-474, Order dated January 7, 2000.
[149] Direct Testimony of Valerie L. Scott of December 19, 2003 (Case No. 2003-00433) ("Scott LG&E Direct") at 3; Direct Testimony of Valerie L. Scott of December 19, 2003 (Case No. 2003-00434) ("Scott KU Direct") at 3.

8. Adjustment to eliminate ESM, ECR and FAC in Rate Refund Account 449

This adjustment has been made to eliminate the impact of the revenues recorded in the test year associated with the ESM, ECR and FAC from Rate Refund Account 449. The impact of rate mechanisms, such as these, should be removed from the test year revenues when assessing the adequacy of base rates.[150]

The AG's witnesses did not take exception to this adjustment.

9. Adjustment to eliminate DSM revenue and expenses

This adjustment has been made to remove the impact of the revenues and expenses associated with the Companies' demand-side management mechanism from the test year revenues and expenses. The impact of rate mechanisms, like the demand-side management mechanism, should be removed from the test year revenues when assessing the adequacy of base rates.[151]

The AG's witnesses did not take exception to this adjustment.

10. Adjustment to annualize year-end customers

This adjustment has been made to annualize revenues based on actual number of customers served at year-end versus the average number of customers used for the test period.[152] The details and calculation of this adjustment were explained by Mr. Seelye in his direct testimony.[153] The operating expense ratio component of the adjustment was calculated consistent with the Commission's practice.

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[150] Scott LG&E Direct at 4; Scott KU Direct at 4.
[151] Seelye LG&E Direct at 53-54; Seelye KU Direct at 26.
[152] Rives LG&E Direct at 11; Rives KU Direct at 10.
[153] Seelye LG&E Direct at 54; Seelye KU Direct at 26-27.

The AG contested the adjustment by recommending what can fairly be described as a non-standard approach.[154] As Mr. Seelye testified, the methodology used by the AG's witness cobbled together two different approaches- one for the residential class and one for all other classes.[155] Both approaches are flawed and inconsistent with the reason the customer year-end adjustment is made in the first place, and are examples of results-driven ratemaking.[156]

Accordingly, the year-end adjustments proposed by LG&E and KU should be accepted and the AG's recommendation should be rejected.

11. Adjustment to reflect annualized depreciation expenses under proposed rates

This adjustment has been made to reflect annualized depreciation expenses under the new rates proposed in this case as applied to plant-in-service as of September 30, 2003.[157]

a. The Companies' proposed new depreciation rates are reasonable

The proposed new rates are based on a depreciation study conducted by AUS Consultants. Earl Robinson, President and Chief Executive Officer of AUS Consultants - Weber Fick & Wilson Division - explained in his direct testimony that the proposed depreciation rates are "reasonable and appropriate given that they incorporate the life and net salvage parameters anticipated for each of the property group investments over their average remaining lives."[158] Under these rates, there is a net increase in annualized depreciation expense set forth as follows: (1) $8,681,141 for LG&E -- Electric Division's plant in service; (2) $812,832 for LG&E -- Gas

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[154] Henkes Direct at 32-38.
[155] Seelye LG&E and KU Rebuttal at 27-28.
[156] Seelye LG&E and KU Rebuttal at 28-30.
[157] Scott LG&E Direct at 4, 15; Scott KU Direct at 4.
[158] Direct Testimony of Earl M. Robinson of December 29, 2003 (Case No. 2003-00433) ("Robinson LG&E Direct") at 2; Direct Testimony of Earl M. Robinson of December 29, 2003 (Case No. 2003-00434) ("Robinson KU Direct") at 2.

Division's plant in service; (3) $1,428,511 for LG&E -- Common Plant's plant in service; and $3,949,872 for KU's plant in service.[159]

Mr. Robinson's depreciation studies are based on plant in service as of December 31, 2002,[160] as opposed to the December 31, 1999, plant in service date for the rates approved in Case Nos. 2001-140 and 2001-141.[161] Mr. Robinson completed a detailed analysis of the Companies' fixed capital books and records, the historical data base of the Companies' plant in service.[162] In addition to the historical data from the Companies' books and records, Mr. Robinson interviewed LG&E and KU personnel relative to current operations and future expectations.[163] He "also incorporated professional knowledge obtained from [his] more than thirty (30) years of utility industry depreciation experience, along with depreciation data assembled from other operating companies."[164]

Mr. Robinson's depreciation rates, and thus the depreciation expense, were developed by utilizing the Straight Line Method, the Broad Group Procedure and the Average Remaining Life Technique.[165] Mr. Robinson gave the following reasons for using this method, procedure and technique:

> The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The straight line method is widely understood, recognized, and utilized almost exclusively for depreciating utility property. The broad group procedure recovers the Company's investments over the average period of time in which the property is providing service to the Company's customers, and was the utilized depreciation procedure. Lastly, the annual depreciation amount utilized needs to be based upon the productive life over

[159] Robinson LG&E Direct at 24-25; Robinson KU Direct at 22.
[160] Robinson LG&E Direct at 1; Robinson KU Direct at 1.
[161] Case Nos. 2001-140 and 2001-141, Orders of December 3, 2001, at 4.
[162] Robinson LG&E Direct at 2; Robinson KU Direct at 2.
[163] Robinson LG&E Direct at 3; Robinson KU Direct at 3.
[164] Id.
[165] Robinson LG&E Direct at 6; Robinson KU Direct at 6.

> which the undepreciated capital investment is recovered. The Company's utilization of the applicable annual depreciation over the average remaining life assures that the Company's property investment is fully recovered over the useful life of the property, and inter-generational inequities are avoided. The determination of the productive remaining life for each property group includes a study of both past experience and future expectations. Finally, the approach is consistent with depreciation methods and procedures generally utilized and accepted by this Commission in the Company's rate Order at KPSC Case No. 2001-141 [and Case No. 2001-140] dated December 3, 2001.[166]

Using the foregoing method, procedure and technique for both LG&E and KU, Mr. Robinson developed depreciation rates for the Companies that included four principal elements: (1) plant in service by vintage; (2) book depreciation reserve; (3) future net salvage and (4) composite remaining life from the applicable property group.[167]

b. The AG's proposed depreciation rates are unreasonable

Michael J. Majoros, Jr. presented depreciation testimony on behalf of the AG. Mr. Majoros also conducted a study of depreciation rates for LG&E and KU and concluded that depreciation expense should be reduced significantly below test year levels. Under his approach, Mr. Majoros made the following recommendations in comparison with test year experience: (1) a decrease of $15,476,738 for LG&E – Electric Division's plant in service; (2) a decrease of $5,402,812 for LG&E – Gas Division's plant in service[168]; and (3) an increase of $1,402,439 for LG&E – Common Plant's plant in service.[169] After making adjustments to the foregoing recommendations due to changes in rates, Mr. Majoros recommended that total LG&E depreciation expense should be decreased $17,355,497 below test year levels.[170] Mr. Majoros' Kentucky Utilities Analyses, Calculations & Quantifications contain the recommendation that

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166 Robinson LG&E Direct at 6-7; Robinson KU Direct at 6.
167 Robinson LG&E Direct at 8-9; Robinson KU Direct at 8.
168 The Gas Division depreciation expense is no longer at issue. Partial Settlement, Stipulation and Recommendation at 1.2.
169 Majoros Exhibit (MJM-3), p. 3 of 4.
170 Majoros Exhibit (MJM-3), p. 4 of 4.

KU's depreciation expense be decreased $26,961,914 below test year levels,[171] although his direct testimony indicates that the decrease should be "$23.1 million."[172]

The rebuttal testimony of Mr. Robinson demonstrates the numerous errors and flaws in Mr. Majoros' depreciation analysis and explains why his recommendations should be rejected.[173]

c. The stipulated depreciation rates are also reasonable

Section 3.3 of the Partial Settlement, Stipulation and Recommendation states:

> The signatories hereto, except the AG, agree that the depreciation rates of the Utilities shall remain the same as approved in the orders of December 3, 2001, in Case Nos. 2001-140 and 2001-141, until the approval by the Commission of new depreciation rates for the Utilities, for which the Utilities shall seek approval by filings made in their next general rate cases or June 30, 2007, whichever occurs earlier. The Utilities depreciation filings shall be based on plant in service as of a date no earlier than one (1) year prior to such filing. From and after the effective date hereof, the Utilities shall maintain their books and records so that net salvage amounts may be identified.

The Companies' actual test year depreciation expense resulted from the application of the depreciation rates approved by this Commission in the orders of December 3, 2001, in Case Nos. 2001-140 and 2001-141.[174] The Companies and every party to this proceeding, except the AG, have stipulated that the existing, or test year actual, depreciation rates shall remain in effect until the approval of new rates by this Commission. Thus, for purposes of determining the revenue requirement for LG&E's electric operations and for KU, at a minimum, the annualized test year level of depreciation of expense is appropriate.

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[171] Majoros Exhibit (MJM-4), p. 2 of 2.

[172] Direct Testimony of Michael J. Majoros, Jr. of March 23, 2004 (Case Nos. 2003-00433 and 2003-00434) ("Majoros Depreciation Direct") at 5.

[173] Rebuttal Testimony of Earl M. Robinson of April 26, 2004 (Case Nos. 4003-00433 and 2003-00434) ("Robinson LG&E and KU Rebuttal"), *passim*.

[174] The depreciation rates are set forth in Exhibit A to the Settlement Agreement dated October 31, 2001, and approved by the Commission in the orders of December 3, 2001 in Case Nos. 2001-140 and 2001-141.

d. The AG's radical net salvage proposals are without merit

Perhaps the most contentious and certainly the most illusionary element in this proceeding are the AG's contentions concerning the future net salvage component of depreciation rates.

Net salvage is the difference between gross salvage (what is received when an asset is disposed of) and the cost of removing it from service.[175] Positive net salvage results when gross salvage exceeds the cost of removing the asset from service.[176] Negative net salvage results when the cost of removing the asset from service exceeds the gross salvage value.[177] The cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise retiring/removing plant, as well as any environmental clean up costs associated with the property. Salvage includes proceeds received for any sale of plant.[178] Common sense dictates that costs of removal must be incurred at the end of the property's life, whether or not there is any legal obligation to remove the plant or remediate the site where it was located.

Mr. Majoros objects to Mr. Robinson's methodology by which net salvage is treated in depreciation rates. However, Mr. Robinson testified, "The study methodology utilized has been extensively set forth in depreciation textbooks and has been the accepted practice by depreciation professionals for many decades."[179] Mr. Robinson further testified as follows about his approach to the development of depreciation rates:

> That process is consistent with the American Institute of Certified Public Accounting ("AICPA") and National Association of Regulatory Utility Commissioners ("NARUC") depreciation definitions, and is also supported by the treatise known as *Public*

[175] Robinson LG&E Direct at 10; Robinson KU Direct at 10.
[176] Id.
[177] Id.
[178] Id.
[179] Robinson LG&E Direct at 11; Robinson KU Direct at 11.

> *Utility Depreciation Practices*, August, 1996, NARUC (the "NARUC Manual").[180]

Thus, since Mr. Robinson's approach is grounded in sound principles of accounting and depreciation practice, the results thereof are reasonable. As indicated above, Mr. Robinson has recommended depreciation expense in excess of the depreciation expense actually incurred during the test year in order to properly reflect treatment of net salvage. In addition, eleven out of twelve parties to these proceedings have stipulated that the depreciation rates in effect during the test year should remain in effect until new rates are approved in the Companies' next rate case or 2007, whichever occurs earlier. The Commission should give significant weight to the stipulation in determining the reasonableness of the annualized test year level of depreciation expense.

The AG, however, has offered Mr. Majoros to urge significant reduction in the Companies' depreciation expense. Mr. Majoros has offered a result-oriented, rarely accepted approach to depreciation analysis that he attempts to support with diversion and misinterpretation of legal, accounting and depreciation principles.

Mr. Majoros disagrees with traditional approaches to the treatment of net salvage in depreciation rates and claims that SFAS No. 143 and FERC Order No. 631 support his approach. They do not. Mr. Majoros also calculates the useful lives of certain items of plant by applying the longest possible choice of life to the item in order to reduce the depreciation rates. These result-oriented approaches to depreciation expense are without intellectual integrity and should be ignored.

Mr. Majoros proposes the elimination of net salvage as an element of depreciation rates and, instead, proposes to treat net salvage, or cost of removal, like an operating expense at the

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[180] Robinson LG&E and KU Rebuttal at 4.

time the plant is removed from service.[181] This approach has the effect of deferring the cost of removal to the end of the life of the asset. As a result, there are intergenerational inequities because the customers who had the use of the asset are not paying the cost of removal; rather, the customers who happen to be present at the end of the life of the asset pay the cost of removal.[182]

Mr. Majoros' approach is rarely accepted by regulatory agencies. In fact, Mr. Majoros admits that Mr. Robinson's approach, not his own approach, is the one many utilities have used and is the recommended approach in the NARUC Manual.[183] Mr. Majoros cites to two proceedings before this Commission involving Jackson Energy Cooperative and Fleming-Mason Cooperative in which his approach to net salvage was adopted on a trial basis.[184] Of course, Mr. Majoros failed to disclose that this Commission further stated in the Jackson Energy case, "In addition, it is hoped that Jackson Energy's net salvage data will be more complete by that time, and that any new study would be able to incorporate a net salvage component into the depreciation rates recommended."[185] A similar sentence appears in the Fleming-Mason order.[186] At the hearing in this proceeding, Mr. Majoros reluctantly admitted that the foregoing limiting language appeared in both orders.[187]

In his direct testimony, Mr. Majoros claims that the Missouri Public Service Commission in two cases has recently adopted his approach to the treatment of net salvage in depreciation rates.[188] One of the cases cited in support of that proposition was the order dated June 28, 2001, in Case No. GR-99-315, *In the Matter of Laclede Gas Company's Tariff to Revise Natural Gas*

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181 Majoros Depreciation Direct at 26.
182 Robinson LG&E and KU Rebuttal at 1-2.
183 Majoros Depreciation Direct at 24.
184 Majoros Depreciation Direct at 30-31, citing to *In the Matter of: The Application of Jackson Energy Cooperative for an Adjustment of Rates*, Case No. 2000-373, Order dated May 21, 2001, at 33-34, and *In the Matter of: Adjustment of Rates of Fleming-Mason Cooperative*, Case No. 2001-00244, Order dated August 7, 2002, at 23.
185 Case No. 2000-373, Order dated May 21, 2001, at 48.
186 Case No. 2001-00244, Order dated August 7, 2002, at 33.
187 TE, Volume III, at 160-162.
188 Majoros Depreciation Direct at 31.

Rate Schedules. It is true that net salvage was separated from depreciation rates in that case. Mr. Majoros, however, failed to tell the Commission the rest of the story. That order was appealed and on March 4, 2003, the Missouri Court of Appeals, Western District, held that the order of June 28, 2001, was not supported by sufficient findings of fact and dismissed and remanded the case to the Missouri Public Service Commission with instructions to provide clearer, more detailed findings of fact that include the rationale for the findings.[189] The Laclede Gas Company case has been set for further hearing on July 16, 2004.[190] The Court of Appeals opinion is instructive:

> The Commission's findings of fact also imply that the Staff's depreciation method of calculating net salvage value is less likely to result in Laclede overrecovering from its customers than Laclede's depreciation method. The Commission's findings of fact fail, however, to support such a contention. No evidence or facts of any nature are cited by the Commission to support this conclusion. Because the Commission failed to provide any support for its finding that Laclede's depreciation reserves are the result of how net salvage is calculated, its findings of fact are conclusory. Similarly, the Commission's findings of fact stating that the Staff's depreciation method is less likely to result in overrecovery from Laclede's customers are conclusory for failing to provide any support of this finding.[191]

Mr. Majoros' testimony in this proceeding fails because it is similarly conclusory with respect to whether over-recovery will occur using the Companies' depreciation methodology; whether the Companies' depreciation reserves are at the appropriate amount and, if not, whether that is the result of the way that net salvage is treated; and whether his method of treating net salvage is less likely to result in over-recovery from the Companies' ratepayers. Indeed, it is likely that, under Mr. Majoros' methodology, future generations of ratepayers will be the victims

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[189] *State ex rel. Laclede Gas Company v. Public Service Commission of the State of Missouri*, 103 S.W.3d 813, 819 (Mo. App. 2003), Motion for Rehearing and/or Transfer to Supreme Court denied April 24, 2003.
[190] *In the Matter of Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules* Case No. GR-99-315, Order of May 4, 2004 (2004 WL 962843).
[191] 103 S.W.3d at 818.

of deferred depreciation expense. We respectfully submit that the failure of Mr. Majoros to disclose the actual status of the *Laclede Gas Company* case should be carefully considered by this Commission in determining what weight his testimony should be afforded.

The level of net salvage in the Companies' depreciation reserve was one of Mr. Majoros' red herrings in this proceeding. Mr. Majoros argued that the level of net salvage, $456.4 million, was inappropriate because it represents removal costs that the Companies have not incurred.[192] He said that the level of net salvage resulted from the inclusion of inflated net salvage ratios in prior depreciation rates.[193] Of course, the Commission is well aware that the depreciation reserve resulted from the application of depreciation rates, including net salvage, which this Commission approved in Case Nos. 2001-140 and 2001-141 and previous cases. Mr. Majoros' conclusion that the net salvage ratios are inflated is unsupported by any factual underpinning. Indeed, his client, the AG, agreed to the depreciation rates approved by the Commission in Case Nos. 2001-140 and 2001-141. Certainly the AG would not agree to depreciation rates that contain inflated net salvage ratios.

During the hearing, Mr. Majoros' intensified his attack on the net salvage amount in the depreciation reserve. He asserted that the Companies did not believe that the net salvage accruals were necessary to pay the costs of removal of their assets and said, "they have convinced them [prior Commissions] that they should collect this money, but they're not going to spend it. That's what I believe."[194] When pressed as to the basis for his statement, Mr. Majoros admitted, "No. Nobody has specifically told me that your company doesn't plan on spending that money."[195]

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[192] Majoros Depreciation Direct at 27-28.
[193] Majoros Depreciation Direct at 28.
[194] TE, Volume III, at 163.
[195] TE, Volume III, at 164.

Mr. Majoros' arguments regarding the treatment of net salvage in the depreciation contain more bluster than substance. The fact of the matter is that the $456.4 million amount with which Mr. Majoros takes such offense is the actual net salvage portion of the depreciation reserve accumulated pursuant to depreciation rates during the test year and previous years, which rates have been specifically approved by this Commission. While Mr. Majoros has implied that the number is unconscionably large, it is less than seven (7%) percent of the Companies' gross depreciable plant in service.[196] Mr. Majoros' objection to the size of the depreciation reserve is somewhat ironic because amounts added to depreciation reserve are deducted from rate base for ratemaking purposes.[197]

Mr. Majoros tried some more numerical sleight-of-hand both in his direct testimony and at the hearing by throwing out the numbers $49 million and $58 thousand and suggesting that those numbers demonstrate wrongdoing in the treatment of net salvage.[198] He claims that the $49 million is the amount of net salvage Mr. Robinson proposes to recover in depreciation annually while the $58 thousand is the average amount of net salvage actually experienced in each of the last five years. In fact, both of those numbers are inventions of Mr. Majoros and not proposals of Mr. Robinson or the Companies. It appears that Mr. Majoros arrived at the $49 million number by deducting all net salvage numbers from Mr. Robinson's proposed depreciation calculations and totaling them, a back of the envelope approach to the matter.[199] The $58 thousand number results from an improper calculation of the net salvage amounts actually incurred in the last five years.[200] Mr. Majoros deducted millions of dollars of

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[196] TE, Volume III, at 61.
[197] TE, Volume III, at 60; *see also* the Dissenting Opinion of Commissioner Connie Murray, *In the Matter of The Empire District Electric Company's Tariff Sheets Designed to Implement a General Rate Increase, Etc.*, Case No. ER-2001-299, Order of September 20, 2001.
[198] Majoros Depreciation Direct at 24 (using a $53,000.00 figure instead); TE, Volume III, at 149.
[199] Net Salvage Sections of Majoros Exhibits (MJM-3) and (MJM-4).
[200] Id.

reimbursements from the net salvage figures that actually represented the cost of relocating existing facilities mandated by the Kentucky Transportation Cabinet. Such tactics should not fool the Commission.

Another red herring tossed out by Mr. Majoros is his suggestion that the implementation of SFAS No. 143 and the entry of FERC Order No. 631 require that net salvage be recovered separately from depreciation. This suggestion appears throughout his direct testimony and cross-examination, but when pressed on the issue, Mr. Majoros admitted that neither pronouncement requires such treatment. As to the impact of SFAS No. 143 on the treatment of net salvage, Mr. Majoros finally admitted that it does not require the separation of net salvage from depreciation rates.[201] As to the impact of FERC Order No. 631, after torturous evasion of the Staff's cross-examination, Mr. Majoros finally acknowledged that such order does not require the separation of net salvage from depreciation rates.[202] Mr. Majoros clearly knew that FERC Order No. 631 does not require separation of net salvage from depreciation because he proposed such separation to FERC in response to the Order No. 631 Notice of Proposed Rulemaking and FERC rejected his proposal.[203] Those two pronouncements relate only to the manner in which net salvage must be revealed in the subject companies' books and records and they specifically disclaim how utilities are to treat net salvage in depreciation rates.

Mr. Majoros' results-oriented approach to depreciation rates is best exemplified by his determination of service lives of certain accounts about which he disagrees with Mr. Robinson. In nearly every instance, for the eleven accounts at issue, Mr. Majoros chose the longest life

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[201] TE, Volume III, at 155-157.
[202] TE, Volume III, at 167-171.
[203] Response of the Attorney General to KU's Data Request, Item No. 11; Response of the Attorney General to LG&E's Data Request, Item No. 14.

available in the data as the service life to be used for those accounts.[204] For example, in Kentucky Utilities Account No. 353.2, Station Eq – Non Sys Cont/Com-Microwave, the current life/curve is 18-R4. The Best Fit (Actuarial) life/curve, a strictly empirical determination, is 38-L15.[205] That is the life/curve that Mr. Majoros chose, even though microwave communications equipment is commonly known to have much shorter lives than 38 years. In Kentucky Utilities Account No. 356, Overhead Conductor & Dev, the current life/curve is 45-R3. The Best Fit (Actuarial) life/curve is 62-R3. The Industry Data Range calls for lives from 20 to 60 years, with an average of 42 years. It is no surprise that Mr. Majoros chose the 62-R3 life/curve.[206] Similarly, for Louisville Gas & Electric Account No. 353.1, Station Eq – Non Sys Cont/Com, the current life/curve is 44-S3. The Best Fit (actuarial) is 57-R2. The Industry Data Range calls for lives from 5 to 57 years, with an average life of 37 years. Again, Mr. Majoros chose the longest available life, 57-R2.[207]

e. Summary

The test year level of depreciation expense is fair, just and reasonable and at a minimum should be utilized to determine the revenue requirements of the LG&E electric operations and KU operations. That expense is based on depreciation rates to which the AG and the Companies agreed and which this Commission approved in 2001. The Partial Settlement, Stipulation and Recommendation also provides that the lower annualized test year level of depreciation expense is reasonable.

The Companies demonstrated through the evidence offered by Mr. Robinson that the higher proposed depreciation expense is also reasonable. The AG's attempt to reduce drastically

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[204] Robinson LG&E and KU Rebuttal at Exhibit EMR-3, pp. 1-2.
[205] Robinson LG&E and KU Rebuttal at Exhibit EMR-3, p. 1.
[206] Id.
[207] Robinson LG&E and KU Rebuttal at Exhibit EMR-3, p. 2.

the level of depreciation expense should be rejected. His witness, Mr. Majoros, advocates an approach to depreciation that is seldom accepted and is contrary to established principles of depreciation. Most importantly, Mr. Majoros advocates the creation of intergenerational inequities by deferring until the end of assets' lives the recovery of the cost of removal.

For the reasons set forth above, at least the annualized test year level of depreciation expense should be utilized for the determination of the LG&E electric and KU revenue requirements, including the adjustment to reflect the annualized depreciation expense.

12. Adjustment to reflect increases in labor and labor-related costs

This adjustment has been made to reflect known and measurable increases in labor and labor-related costs as applied to the twelve months ended September 30, 2003. The calculation includes specific adjustments for the contractual increase in union employees' wages and the related increase in the FICA employer payroll taxes and Company match of 401(k) contributions.[208] This adjustment is calculated in accordance with the methodology approved by the Commission Case No. 2000-080.[209]

The AG's witnesses did not take exception to this adjustment.

13. Adjustment for pension and post-retirement expenses

This adjustment is necessary to annualize pension and post-retirement medical benefit expenses. This adjustment is calculated by subtracting the net periodic cost calculated by the Companies' actuary, Mercer, for 2003 from the amount included in the test period.[210]

The AG has recommended that the Commission reject this adjustment.[211] This adjustment for pension and post-retirement expenses, however, is necessary to annualize the test

[208] Scott LG&E Direct at 5; Scott KU Direct at 5.
[209] Scott LG&E Direct at 15-16; Scott KU Direct at 5.
[210] Scott LG&E Direct at 6, 16; Scott KU Direct at 6.

period ended September 30, 2003 to reflect the 2003 known and measurable pension and post-retirement expenses calculated by Mercer.

The AG recommends that the Commission only allow the test year expense. However, Mr. Majoros, on behalf of the AG, relies on three erroneous assumptions and fails to present any support for his speculative contentions.[212]

First, Mr. Majoros assumes that "amortization of actuarial (gain) or loss" are "changes in the ABO due to revisions in predicted retirement periods of the Companies' employees."[213] An ABO, or accumulated benefit obligation, represents the present value of the benefit to date. The Companies believe that Mr. Majoros meant PBO, or projected benefit obligation, instead. A PBO is the benefit of future salaries based on the participants' years of service to date. Actuarial gains or losses may be changes in either the PBO due to changes in assumptions, such as discount rates, retirement rates, turnover rates, mortality rates, or salary increase rates or changes in the plan assets due to changes in actual gains or losses experienced. This definitional error by Mr. Majoros affects his other assumptions about the ABO.[214]

In addition, in arguing that the interest rate chosen for the actuarial calculation "creates volatility in pension costs," Mr. Majoros contends that:

> a lower interest rate has the counter-intuitive effect of increasing the interest costs on the ABO. That is because as the present value of the ABO increases, the annual accretion in that value is correspondingly larger, even at the lower interest rate.[215]

Yet, whether or not a lower interest rate increases the interest cost on the PBO depends on other factors in addition to interest rates, such as the plan demographics.

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[211] Rebuttal Testimony of Valerie L. Scott of April 26, 2004 (Case Nos. 2003-00433 and 2003-00434) ("Scott LG&E and KU Rebuttal") at 11.
[212] Id.; *see also* Henkes Gas Direct at 52; Henkes Electric Direct at 54-55.
[213] Majoros Revenue Requirements Direct at 11.
[214] Id. at 12.
[215] Majoros Revenue Requirements Direct at 12.

Finally, Mr. Majoros argues that the value of KU's pension and post-retirement benefit fund assets "will probably increase" because:

> most companies do not fully revalue their pension assets each year. Rather, they use a "smoothing" technique in which only a one-third of each year's gain or loss is recognized in calculating the capital gains or losses in the funds' asset values. The remaining two-thirds are amortized into the re-evaluation over the next two years.[216]

The assumption that the Companies use such a smoothing technique is incorrect. The Companies use the fair market value methodology to value assets for purposes of SFAS No. 87.[217]

Aside from relying on faulty assumptions, Mr. Majoros also provides no support for his claim that the value of KU's pension and post-retirement benefit fund assets "will probably increase."[218] This is an unsupported and speculative assertion.[219] Further, Mr. Majoros speculates that the 2003 pension and post-retirement benefit costs "may be the peak costs that KU has experienced and that it will experience in the immediate future." Again, there is no independent analysis to verify his statements.[220]

Nevertheless, these erroneous and speculative assertions completely overlook the fundamental reason for the adjustment. This is an annualization adjustment based on the known and measurable change in pension and post-retirement benefit expense occurring in the test year.[221] Mr. Majoros' speculations concern possible changes in the future and have no bearing on the full 12-month period ending September 30, 2003.

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216 Majoros Revenue Requirements Direct at 14.
217 Scott LG&E and KU Rebuttal at 12.
218 Id. at 13.
219 Majoros Revenue Requirements at 15.
220 Scott LG&E and KU Rebuttal at 13.
221 Id. at 14.

14. Adjustment to reflect normalized storm damage expenses

This adjustment has been made to reflect a normalized level of storm damage expenses. The LG&E adjustment is based upon a ten-year average adjusted for inflation while only four years of information was available for KU.[222] The ten-year methodology used was approved by the Commission in Case No. 90-158.[223]

The AG's witnesses did not take exception to this adjustment.

15. Adjustment to eliminate advertising expenses

This adjustment eliminates advertising expenses primarily institutional and promotional in nature. In accordance with Section 2(l) of 807 KAR 5:016, a utility is allowed to recover, for ratemaking purposes, only those advertising expenses which produce a "material benefit" to its ratepayers.[224]

In addition to this adjustment, however, the AG recommends the following amounts be disallowed from LG&E's calculation of the revenue requirement for its electric operations:[225]

FERC Account	Electric
No. 909001	$22,699.00
No. 909002	$ 3,119.00
No. 912001	$13,177.00
No. 912005	$51,455.00

LG&E does not object to this recommendation to disallow the expenses in Account #909001 ($22,699) and Account #909002 ($3,119), but objects to the AG's recommendation to disallow the promotional expenses in Account #912001 ($13,177) and Account #912005 ($41,455).

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222 Scott LG&E Direct at 6; Scott KU Direct at 6.
223 *In the Matter of: Adjustment of Gas and Electric Rates of Louisville Gas and Electric Company*, Case No. 90-158, Order dated December 21, 1990.
224 Scott LG&E Direct at 6, 17; Scott KU Direct at 6.
225 Henkes Electric Direct at 40.

As envisioned under 807 KAR 5:016, the expenses in Account 912001 are related to economic development and produce a "material benefit". LG&E incurred these promotional expenses to assist and attract employers to the Commonwealth who are "selecting" the location of their facility, not their electric supplier. By working closely with state and local governments, the relocation of new businesses and expansion of existing businesses are encouraged and the number of jobs and available amount of potential taxes are increased.[226]

Additionally, the Commission required the following commitment in approving the Powergen and E.ON transactions:

> E.ON and Powergen commit to maintaining LG&E's and KU's proactive stance on developing economic opportunities in Kentucky and supporting economic development ... throughout LG&E's and KU's service territories.[227]

Consistent with the fulfillment of this commitment, economic development expenses are an appropriate part of the Companies' cost of providing customer service. Economic development expenses were not removed in LG&E's Case No. 98-426 or KU's Case No. 98-474, but the Companies acknowledge such expenses were not allowed in LG&E's last gas base rate case, Case No. 2000-080.

Furthermore, the expenses in Account 912005 relate to customer satisfaction surveys and utility industry research. These expenses help the Companies provide better customer service as evidenced by the Companies' multiple J. D. Power awards and thereby should be allowable in determining base rates.[228]

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[226] Scott LG&E and KU Rebuttal at 3-5.
[227] *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of Powergen plc,* Case No. 2001-104, Order of August 6, 2001; *In the Matter of: Joint Application of Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of a Merger*, Case No. 2000-095, Order of May 15, 2000.
[228] Scott LG&E and KU Rebuttal at 5.

The Companies recommend the Commission deny the AG's adjustment as a matter of sound regulatory policy consistent with 807 KAR 5:016 and its requirement for the Companies to support economic development. These expenses produce a material benefit for customers.

16. Adjustment to reflect amortization of rate case expenses

This adjustment is necessary to include the expenses incurred in conjunction with this base rate case. The estimations of $1,000,739 by LG&E and $1,057,368 by KU, both to be amortized over 3 years, will be trued up as actual expenditures are incurred. The Commission previously approved the recovery of rate case expenses in Case 2000-080.[229]

Although the AG agrees that there should be an adjustment to recognize rate case expenses in the Companies' revenue requirements, the AG mistakenly believes that the Companies are requesting the recovery of the estimated cost of the rate case expenses.[230] This estimate was used only for the purpose of calculating the revenue requirement at the time of filing the Companies' Applications. In fact, the Companies are requesting recovery of their actual rate case expenses in these cases in accordance with Commission policy. In response to PSC 1-57 and its monthly updates, the Companies have provided the Commission their actual rate case expenses. In the most recent update, filed May 28, 2004, KU's actual rate case expenses totaled $1,190,710 and LG&E's electric actual rate case expenses totaled $687,778.

17. Adjustment to reflect amortization of ESM audit expenses

This adjustment is necessary to reflect the expenses incurred by LG&E for the ESM audit. The amount of the adjustment is based on expenses incurred through the end of the Commission's investigation; the result is amortized over 3 years at a rate of $58,333 per year.[231]

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[229] Scott LG&E Direct at 6-7, 17; Scott KU Direct at 6-7.
[230] Scott LG&E and KU Rebuttal at 5-6.
[231] Scott LG&E Direct at 7; Scott KU Direct at 7.

The AG's witnesses did not take exception to this adjustment.

18. Adjustment to remove One-Utility costs

This adjustment is necessary to remove the amortization of One-Utility costs as a non-recurring expense. These costs were completely amortized by September 30, 2003.[232] The establishment of the regulatory asset and amortization of the One-Utility costs was approved by the Commission in Case No. 2000-080.[233]

The AG's witnesses did not take exception to this adjustment.

19. Adjustment for injuries and damages – FERC Account 925

This adjustment is made to normalize the expense levels in Account 925 "Injuries and Damages." This normalization is based upon a five-year average adjusted for inflation, consistent with the methodology used for the storm damage adjustment.[234]

The AG recommends that the five-year CPI-adjusted average should be moved forward by approximately one year, so that the five-year period begins with 1999 and ends with the test year.

In order to avoid over-weighting the three-month period ending December 31, 2002, the Companies excluded the test year expense. By including the test year in the five-year average, both the 2002 and the test year results would include this three-month period.

Using a multi-year normalization of expenses is more appropriate because a longer historical period in the normalization of expenses such as injuries and damages, as adjusted for inflation, results in a better representation of normal expenses. To resolve this issue, the Companies recommend this adjustment be calculated consistent with the methodology used to

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[232] Scott LG&E Direct at 7, 17; Scott KU Direct at 7.

[233] *In the Matter of: Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order dated September 27, 2000.

[234] Scott LG&E Direct at 7-8, 18; Scott KU Direct at 7.

calculate their storm damages adjustment. VLS Rebuttal Exhibit 2 shows the injuries and damages expense normalization adjustment calculated using a ten-year average, including the test period, adjusted for inflation.

20. Adjustment for VDT net savings to shareholders

This adjustment is to reflect the Value Delivery Team ("VDT") net savings to shareholders recognized by the Commission in its December 3, 2001 Order in Case No. 2001-169.[235] Under the terms of the Settlement Agreement in that proceeding, the customers receive 40% of the net savings, distributed through the Value Delivery Surcredit Rider, and the shareholders receive 60% of the net savings.[236] Absent the substantial savings realized by both Companies, the necessary increase in rates would be much higher than requested in this rate case. Thus, although the adjustment to recognize the shareholder portion of savings under the VDT initiative results in an upward adjustment of operating expenses, the overall effect of the VDT program has been to lower customers' bills, with the benefit to be shared by customers and shareholders, as per the Commission Order. This adjustment to expenses is consistent with the ratemaking treatment of the shareholders' portion of the merger surcredit savings in Case No. 98-426.

The AG's witnesses did not take exception to this adjustment.

21. Adjustment to reflect VDT settlement agreement

This adjustment is to true up the VDT customer surcredit and amortization of expenses approved by the Commission in its December 3, 2001 Order in Case No. 2001-169[237] as adjusted

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[235] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations*, Case No. 2001-169, Order dated December 3, 2001.
[236] Scott LG&E Direct at 8; Scott KU Direct at 8.
[237] Scott LG&E Direct at 9, 19; Scott KU Direct at 9; *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and*

by the revised tariff filed January 31, 2002, based on revised estimated costs as of December 31, 2001. Although the Companies incurred and deferred expenses in excess of their estimate as of December 31, 2001, they have not sought to reduce the net VDT surcredit paid to their customers by these expenses and the shareholders have borne the costs in their entirety. The Companies believe their deferral of these expenses was appropriate since the total expenses were still within the limit established in the global settlement.

The AG's witnesses did not take exception to this adjustment.

22. Adjustment for merger savings

This adjustment is made to reflect the current customers' and shareholders' portions of the merger savings approved by the Commission in its October 16, 2003 Order in Case No. 2002-00430.[238] Absent this adjustment to reflect the 50/50 split established by the Merger Surcredit Settlement Agreement between the Companies, AG, KIUC and LFUCG, the shareholders would lose their share of the savings approved by the Commission.[239]

The AG's witnesses did not take exception to this adjustment.

23. Adjustment to eliminate merger amortization expenses

This adjustment is necessary to reflect the elimination of merger amortization expenses from the LG&E Energy Corp. acquisition of KU Energy Corporation approved by the Commission in Case No. 97-300.[240] The merger expenses were fully amortized by September

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Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations, Case No. 2001-169, Order dated December 3, 2001.

238 *In the Matter of: Louisville Gas and Electric Company's Plan to Address the Future of the Merger Surcredit Approved by the Kentucky Public Service Commission in Case No. 1997-0300*, Case No. 2002-00430, Order dated October 16, 2003.

239 Scott LG&E Direct at 9; Scott KU Direct at 9.

240 *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger*, Case No. 97-300, Order dated September 27, 1997.

30, 2003.[241] The remaining amount of the related regulatory asset was amortized during the test year and will not be a recurring expense.[242]

The AG's witnesses did not take exception to this adjustment.

24. Adjustment for MISO Schedule 10 credits

This adjustment is necessary to reverse a portion of credits received by the Companies from Midwest Independent Transmission System Operator, Inc. ("MISO") during the test year.[243] These credits were applied to billings of MISO's Schedule 10 administrative costs and will not continue after 2003.[244]

The AG's witnesses did not take exception to this adjustment.

25. Adjustment for cumulative effect of accounting change

This adjustment is necessary to fairly reflect the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations, for ratemaking purposes.[245] Under SFAS No. 143, if a legally enforceable asset retirement obligation ("ARO") is deemed to exist, an entity must measure and record the liability for the ARO on its books at fair market value in the period during which the liability is incurred.[246] At the same time, a corresponding and equivalent ARO asset is recorded to recognize the cost of removal as an integral part of the cost of the associated tangible asset. The entity is also required to recognize the cumulative impact on its financial statements. SFAS No. 143 acknowledges that many rate-regulated entities provide for costs related to retirement of certain long-lived assets and recover those amounts in rates charged to their customers. If the timing of cost recognition under this statement and rate recovery methods differ, the regulatory asset or liability must be recorded for the difference subject to SFAS No. 71, Accounting for the

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241 Scott LG&E Direct at 9-10; Scott KU Direct at 9-10.
242 Id.
243 Scott LG&E Direct at 10; Scott KU Direct at 10.
244 Id.
245 SFAS 143, Accounting for Asset Retirement Obligations (June 2001).
246 Scott LG&E Direct at 10-12; Scott KU Direct at 10-12.

Effects of Certain Types of Regulation. For ratemaking purposes, the implementation of SFAS No. 143 overstates the Companies' above-the-line income that is not representative of their operations.

The AG asserts that the Companies "contrived" accounting adjustments in order to create incremental revenue requirements and argues that the credit booked to account 407 was a result of "an unnecessary charge to below-the-line net income."[247] The AG witness, Mr. Majoros, based his accusation on his conclusion that he could not find any above-the-line credits that would reduce the incremental revenue requirements to a position of revenue neutrality when he stated:

> Q. Are there any offsetting above-the-line credits that reduce these amounts to revenue neutrality in the rate cases?
>
> A. I have not found any above-the-line credits that reduce these incremental revenue requirements to revenue neutrality.[248]

At the hearing on May 6, 2004, while adopting his pre-filed testimony, Mr. Majoros confessed that after reading the rebuttal testimony of Ms. Scott he found the Companies' offsetting revenue credits and offered to withdraw his recommendation that the Companies' SFAS No. 143 adjustment be disallowed.[249] In withdrawing his recommendation, however, Mr. Majoros attempted to offer surrebuttal. Caught, Mr. Majoros then refused to withdraw his recommendation, notwithstanding his earlier admission that he was wrong, contending the adjustment was only a "pittance."[250]

[247] Majoros Revenue Requirements Direct at 16; Michael J. Majoros SFAS No. 143 Testimony of March 23, 2004 (Case Nos. 2003-00433 and 2003-00434) ("Majoros SFAS No. 143") at 12-16.
[248] Majoros SFAS No. 143 at 14.
[249] TE, Volume III, at 134.
[250] Id. at 141-142.

When adopting SFAS No. 143 and FERC Order No. 631, the Companies were required to record a cumulative effect adjustment.[251] In accordance with the FERC pronouncement, this cumulative effect was recorded in account 435, Extraordinary Deductions, which is to "be debited with losses of unusual nature and infrequent occurrence."[252]

In general, FERC Order No. 631 adopts the SFAS No. 143 requirements. Unfortunately, FERC did not recognize the ratemaking implications of recording a cumulative effect adjustment in the FERC-prescribed below-the-line account 435 versus the FERC-prescribed above-the-line regulatory credit account 407. The Companies' proposed adjustment simply reverses the non-recurring "above-the-line" regulatory credit recorded during the test year to achieve the "revenue neutral" result desired by all parties involved.

The AG also argues that removal costs related to assets without a legal liability should be recognized as regulatory liabilities if the requirements of SFAS No. 71 are met. However, in accordance with FERC Order 631, the Companies have separated these costs of removal through reclassification of the amounts to account 108 sub-accounts. As recognized by FERC in its order, the calculation of these amounts could be difficult or perhaps impossible for some companies. Thus, this provision could be prospectively adopted if the previously recorded amounts could not be identified. Between the date the FERC order was issued and its calendar year end, the Companies calculated these amounts and made the reclassifications required by FERC Order 631. There was no net impact of the reclassifications because they were merely among the 108 series of accounts; therefore, these entries had no bearing on the adoption of SFAS No. 143.

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[251] Scott LG&E and KU Rebuttal at 15.
[252] Id.

The AG further argues that the future cost of removal is not capitalized if the Companies do not have legal obligations. Even though no accrual is established for the cost of removal without a legal obligation similar to the accrual established under SFAS No. 143, the traditional practice for utilities is to recognize the cost of removing all assets through depreciation expense and accumulated depreciation. This practice charges the costs of ultimately replacing or removing assets to the ratepayers benefiting from their use.

For ratemaking purposes, the Companies are required to remove all effects of adopting SFAS No. 143 as indicated in the Commission's December 19, 2003 Stipulation. Accordingly, the Companies have recorded all expense impacts of SFAS No. 143 as either regulatory assets or regulatory liabilities and continued depreciating all assets using the Commission-approved depreciation rates. By using the approved depreciation rates with a cost of removal component and removing the effects of SFAS No. 143, the Companies will not charge excessive depreciation.

The December 19, 2003 Stipulation was made recognizing that the accounting under SFAS No. 143 did not dictate the regulatory treatment of depreciation. In fact, SFAS No. 143 recognized that regulated entities use depreciation rates that include a cost of removal component and might be subject to different depreciation accounting for financial and regulatory accounting purposes. Paragraph 20 of SFAS No. 143 provides as follows:

> Many rate-regulated entities currently provide for the costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of this Statement; others result from costs that are not within the scope of this Statement. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with the Statement and, therefore, may result in a difference in the timing of recognition of period costs for financial

> reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. If the requirements of Statement 71 are met, a regulated entity also shall recognize a regulatory asset or liability for differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting pursuant to this Statement and rate-making purposes.

Paragraph 38 of FERC Order 631 similarly recognized the differences in financial and regulatory accounting practices for assets without a legal liability, as follows:

> Instead we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes.

By including the cost of removal component in its depreciation rates, the Companies ensure that customers benefiting from the use of the assets are also paying a portion of their ultimate replacement or removal costs. As detailed in the discussion of depreciation expense above, the AG's assertion that the Companies have over-collected $456 million from ratepayers is without merit.

26. Adjustment for IT staff reduction

This adjustment has been made to reflect the October 2003 reduction of 27 employees in the Information Technology department of LG&E Energy Services, Inc. The labor and labor-related expenses charged to the Companies during the test year are reduced by one-third of the costs to effectively amortize them over a three-year period.[253] The AG witness, Mr. Henkes,

[253] Scott LG&E Direct at 12-13, 19; Scott KU Direct at 12-13.

agrees with the adjustment subject to recognition of the additional IT staff reduction related cost savings.[254]

27. Adjustment to remove E.W. Brown legal expenses

This adjustment is necessary to remove non-recurring legal expenses in connection with the Alstom combustion turbine litigation in the test year. LG&E owns a 38% interest and KU owns a 62% interest in the two combustion turbines located at the E.W. Brown Power Station.[255] The expense was allocated on the basis of the ownership interests.

The AG's witnesses did not take exception to this adjustment.

28. Adjustment for customer rate-switching

This adjustment is made to reflect the decrease in revenue resulting from an electric customer switching from a special contract rate to KU's proposed NCLS and another customer switching from a special contract rate to Rate LP-TOD.[256]

The AG's witnesses did not take exception to this adjustment.

29. Adjustment for federal and state income tax expenses for pro forma adjustments

This adjustment is for federal and state income taxes corresponding to the base revenue and expense adjustments discussed above. LG&E Reference Schedule 1.36 and KU Reference Schedule 1.34 show the calculation of a composite federal and state income tax rate using a federal corporate income tax rate of 35%, and a Kentucky corporate income tax rate of 8.25%.[257] As shown on those Reference Schedules, the composite federal and state income tax rate is 40.3625%.[258]

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[254] Henkes Gas Direct at 43; Henkes Electric Direct at 45.
[255] Scott LG&E Direct at 13; Scott KU Direct at 13.
[256] Seelye LG&E Direct at 55; Seelye KU Direct at 27.
[257] Rives LG&E Direct at 19 and Exhibit 1; Rives KU Direct at 15-16 and Exhibit 1.
[258] Id.

The AG argues that the proposed state income tax rate of 8.25% should be replaced with the effective state income tax rate from the Companies' most recent 2002 consolidated Kentucky corporation income tax returns. However, the Commission has applied the state statutory tax rate in the Companies' past rate cases and consistent treatment must be afforded.[259] The effective state income tax rates recommended by the AG were less than the statutory rate due to credits and apportionment adjustments from out-of-state activities which may not be necessarily available in the future.[260] The statutory income tax rate proposed by the Companies is objective, known and measurable, easily understood and verified, and not distorted by non-recurring items or apportionment adjustments from out-of-state activities.[261]

Nevertheless, if an effective income tax rate is used for the Companies, it is critical that the Commission apply an all-inclusive effective rate.[262] For instance, the Commission should allow LG&E to recover the Indiana taxes it pays on a portion of its off-system sales, all of which benefit Kentucky customers.[263] This results in an effective tax rate of 8.07% for LG&E.[264] Likewise, KU pays taxes in Virginia, Tennessee and Kentucky.[265] Because KU's total taxable income is apportioned for Kentucky and non-Kentucky property, payroll and receipts factors, the effective state income tax rate referenced in PSC 2-15(e)(3) is distorted because it compares the total Kentucky taxes to all of KU's taxable income.[266] If the Virginia property, payroll, and receipts are excluded, the 2002 effective state income tax rate is 7.98%.[267]

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[259] Rives LG&E and KU Rebuttal at 9.
[260] Id. at 9-10.
[261] Id. at 10.
[262] Id.
[263] Id.
[264] Id.
[265] Id.
[266] Id.
[267] Id.

30. Adjustment for federal and state income taxes corresponding to the annualization and adjustment of year-end interest expense.

This adjustment is for federal and state income taxes corresponding to the annualization and adjustment of year-end interest expense. The Commission has traditionally recognized the income tax effects of adjustments to interest expense through an interest synchronization adjustment. The Companies calculated the adjustment following the methodology used by the Commission in its order in Case No. 2000-080.[268] The total capitalization amount for LG&E is taken from Rives Exhibit 2 and is multiplied by LG&E's weighted cost of debt, and that amount is then compared to LG&E's interest per books (excluding other interest) to arrive at the interest synchronization amount.[269] The same calculation was made for the KU adjustment.[270] The composite federal and state income tax rate has been applied to the interest synchronization amount.

With the correction identified in the Companies' rebuttal testimony, the AG should accept the adjustment.

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[268] *In the Matter of: Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order dated September 27, 2000.

[269] Rives LG&E Direct at 17 and Exhibit 2. When calculating its electric and gas operating tax provision for the rate case test year, LG&E inadvertently failed to include interest expense on debt to associated companies and interest costs related to the accounts receivable securitization. Rives LG&E and KU Rebuttal at 11. In addition, LG&E overstated the interest expense charged to electric and gas operations for the test year due to an incorrect interest expense allocation between electric and gas. Id. Accordingly, the interest synchronization adjustment should be a decrease in operating expense of $406,954 for LG&E's electric operations.

[270] Rives KU Direct at 16 and Exhibit 2.

31. Adjustment for income tax true-ups and adjustments

This adjustment is for income tax true-ups and adjustments made during the test year that relate to prior periods, and is in accordance with the Commission's approval of this type of adjustment in Case No. 2000-080.[271]

The AG's witnesses did not take exception to this adjustment.

B. Pro-Forma Adjustments for Known and Measurable Changes for KU's Operations

1. Adjust for sales tax refunds

This adjustment is for sales tax refunds KU received during the test year that related to sales tax expenses incurred prior to the test year. This adjustment removes the amount of the refund from the test year since these refunds will not occur in the future.[272]

The AG's witnesses did not take exception to this adjustment.

2. Adjust for OMU NOx expense

This adjustment is to reflect an increase in purchase power demand costs. Under the current power contract between KU and Owensboro Municipal Utilities ("OMU"), KU will pay OMU an increase in demand charges for KU's portion of OMU's environmental compliance with NOx regulations beginning July 1, 2004. The adjustment reflects KU's estimate of increases in demand charges which will begin July 1, 2004.[273] The AG has not expressed a position on this adjustment.

3. Adjust for ice storm expenses

This adjustment is to reflect the normalization of net expenses incurred by KU as a result of the 36-hour ice storm between February 14 and 16, 2003. Central Kentucky received over

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[271] *In the Matter of: Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order dated September 27, 2000.
[272] Scott KU Direct at 13.
[273] Id.

two inches of ice accumulation, interrupting electric service to over 141,000 KU customers. In many places, the ice accumulation increased the load on structural members to more than eight times their design capability. The ensuing restoration effort involved over 2,000 KU, LG&E and contractor personnel. Within one week, all but 9,000 KU customers had service restored.[274]

KU incurred $15.5 million in operating and maintenance costs because of the ice storm, and received an insurance reimbursement of $8.9 million during the test year. This adjustment is to amortize the net amount of $6.6 million over a five-year period. The five-year period is consistent with the amortization approved by the Commission for LG&E's 1974 tornado damage in Case No. 6220 and represents a longer amortization period than that used for the normalization of other storm damage expenses in Rives Exhibit 1 Reference Schedule 1.14.[275]

The AG's witness did not take a position with respect to this adjustment.

4. Adjust for management audit fees

This adjustment is for management audit fees for the 1992 Commission audit of KU. Following that audit, the Commission authorized KU to establish a regulatory asset of the management audit fee annualized over three years. Accordingly, KU is proposing to include one-third of the cost incurred as part of its operating expenses in order to collect the management audit fee.[276]

The AG's witness did not take exception with this adjustment.

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274 Scott KU Direct at 14.
275 Id.
276 Id.

5. Adjust for expenses for retirement of Green River Units 1 and 2

This adjustment is to reduce operation and maintenance expenses for the amounts incurred solely for the operation of KU's Green River Units 1 and 2 during the test year. These units were retired earlier this year and these costs will not be incurred in the future.[277]

The AG's witness did not take exception with this adjustment.

C. Pro-Forma Adjustments for Known and Measurable Changes for LG&E's Electric Operations

1. Adjust for corporate office lease expense

This adjustment reflects changes in LG&E's corporate office lease expenses due to the negotiation of a more favorable lease for the corporate offices located at 220 West Main Street in Louisville. LG&E had recorded rent expense on a normalized basis over the term of the former lease normalizing higher payments that would have been due in the later years of the lease in conformity with SFAS 13, Accounting for Leases. The difference between the actual amounts paid and the normalized amount expensed until cancellation resulted in an accrual for future lease payments that would no longer be made with the cancellation of the lease. During the test year LG&E reversed this accrual. This adjustment removes the credit to expense and establishes the rent expense at the actual annual amount under the new lease.[278]

The AG's witness did not take exception with this adjustment.

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[277] Id. at 14-15.
[278] Scott LG&E Direct at 13, 20.

2. Adjust for Cane Run repair refund

This adjustment is to remove the insurance proceeds received by LG&E during the test year for costs incurred prior to the test year related to the repair of Cane Run Unit No. 5. As a non-recurring item, the insurance reimbursement must be removed from the test year.[279]

The AG's witness did not take exception with this adjustment.

3. Adjust for obsolete inventory write-off

This adjustment is for steam plant inventory that LG&E charged-off its books during the test year because the parts became obsolete. Obsolete inventory write-off will occur from time to time. For this reason, LG&E proposes to amortize this expense over a three-year period.[280]

The AG requests that the Commission reject this adjustment by arguing that it is a non-recurring event.

The obsolete inventory adjustment of LG&E meets the objective of the test period: to set a representative ongoing level of costs going forward to be recovered through base rates. By rejecting the adjustment, a frequently-incurred, reasonable cost of providing service is disallowed. By including the adjustment, a more representative level of annual expenses is reflected for ratemaking purposes. In LG&E's 1988 rate case, Case No. 10064, the Commission reviewed the early retirement of certain scrubbers and the abandonment of underground gas storage fields and identified these items as extraordinary property losses. While not completely disallowing the cost of this property, the Commission instructed LG&E to establish deferred asset accounts and begin an amortization of those assets. Thereby, LG&E was allowed to recover the total cost of the utility plant no longer in service, but not allowed an earned return on

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[279] Id. at 14.
[280] Id. at 14.

the plant retirements or abandonments. LG&E requests the same ratemaking treatment in this case.

4. Adjust for carbide lime write-off

This adjustment relates to the write-off of a payment for carbide lime made by LG&E to Carbide Graphite for use at the Cane Run Power Station. The deposit was written off as a result of Carbide Graphite's bankruptcy. The write-off of this payment is not expected to be a recurring annual expense, but it was incurred to benefit customers by securing carbide lime needed in the scrubber process. LG&E proposes to amortize this expense over a three-year period.[281]

The AG recommends that the Commission reject the adjustment on the basis that it is a non-recurring event. The Commission should reject the contention of the AG because he fails to recognize LG&E's permitted recovery of its prudently incurred costs. LG&E invested in the carbide lime which is now being written off. As a matter of principle, the Company should have the opportunity to recover its investment regardless of the frequency of the write-off. The AG has not demonstrated that any of these investments were incurred improperly or imprudently. Instead, the AG has proposed an unreasonable standard for recovering a customer service investment.

D. Ratemaking treatment of MISO expenses.

The Companies joined MISO to comply with the Federal Energy Regulatory Commission's position that utilities join Independent Transmission System Operators ("ISOs") and, later, Regional Transmission Operators ("RTOs").[282] For the twelve months ending

[281] Id. at 14-15.
[282] Testimony of Michael S. Beer of December 29, 2003 (Case No. 2003-00433) ("Beer LG&E Direct) at 13; Testimony of Michael S. Beer of December 29, 2003 (Case No. 2003-00434) ("Beer KU Direct") at 10.

September 30, 2003, LG&E incurred $2.6 million in MISO Schedule 10 administrative costs.[283] In that same period, KU incurred $3.1 million in Schedule 10 administrative costs.[284] These FERC-approved charges are now part of the Companies' cost-of-service and represent costs that are not currently reflected in the Companies' base rates.[285] LG&E has included $3.3 million in its revenue requirement in this case to account for the ongoing costs of MISO membership.[286] KU has included $3.1 million in its revenue requirement in this case for the same reason.[287] These costs are higher than those noted above for the test year ended September 30, 2003, because the Companies received credits during the test year that they will not receive going forward.[288]

On July 17, 2003, the Commission opened an investigation into the Companies' MISO membership ("MISO case").[289] A hearing has been held in the MISO case, and post-hearing briefs have been submitted. The matter is now before the Commission for decision.

If the Commission determines in the MISO case that the Companies should remain MISO members, it would not affect or alter the Companies' base rate recovery of the ongoing MISO costs as the Companies have proposed in these rate cases.[290] The AG's witness, Mr. Robert J. Henkes, stated that he "take[s] no exception" to LG&E's plan to recover its MISO Schedule 10 costs through base rates pending the Commission's decision in the MISO case.[291]

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[283] Beer LG&E Direct at 13.
[284] Beer KU Direct at 10.
[285] Beer LG&E Direct at 13; Beer KU Direct at 10.
[286] Beer LG&E Direct at 13 - 14.
[287] Beer KU Direct at 10.
[288] Beer LG&E Direct at 14; Beer KU Direct at 10.
[289] *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.*, ("MISO Case"), Case No. 2003-00266, Order dated July 17, 2003.
[290] Beer LG&E Direct at 14; Beer KU Direct at 11.
[291] Henkes Electric Direct at 53. Although he does not address the question directly, it is logical to conclude that Mr. Henkes also would not take exception to the Companies' base rate recovery of their MISO Schedule 10 costs should the Commission determine that the Companies' continued MISO membership is in the public interest.

If, alternatively, the Commission enters an order in the MISO case directing the Companies to exit MISO, the Companies would have to seek and receive a FERC order allowing their exit.[292] While the Companies pursue MISO exit with FERC, they and Mr. Henkes believe that they should continue base rate recovery of their Schedule 10 costs.[293] Should FERC allow the Companies to exit MISO, the Companies expect that FERC would also lawfully determine the appropriate amount of the MISO exit fee.[294] The Companies have asked the Commission in the MISO case to authorize them to create a regulatory asset for the eventual exit fee.[295] Mr. Henkes appears to concur with this approach.[296]

Assuming that FERC allows the Companies to exit MISO and lawfully establishes the amount of the MISO exit fee, for which the Commission allows the Companies to create a regulatory asset, Mr. Henkes suggests a plan for amortizing the Companies' MISO exit fee cost. Appealing to the ratemaking principle of continuity, Mr. Henkes proposes that, rather than having a separate ratemaking proceeding to determine an amortization schedule and terminate rate recovery of the Companies' Schedule 10 costs, the Companies should instead continue to collect the above-requested Schedule 10 costs through the new base rates even after exiting MISO.[297] Mr. Henkes further suggests that the Commission should order the Companies to establish a regulatory liability account for the amounts the Companies continue to recover in base rates for the Schedule 10 costs they no longer incur.[298] The balance in the regulatory liability account would be used to offset the regulatory asset the Companies establish for the

[292] Rebuttal Testimony of Michael S. Beer of April 26, 2004 (Case Nos. 2003-00433 and 2003-00434) ("Beer LG&E and KU Rebuttal") at 2.
[293] Henkes Electric Direct at 53; Beer Rebuttal at 1-2.
[294] Beer Rebuttal at 2.
[295] *See, e.g.*, MISO Case, Pre-filed Direct Testimony of Paul W. Thompson of September 22, 2003 ("Thompson MISO Direct") at 15-16; TE, Volume II, at 158-65.
[296] Henkes Electric Direct at 53-54 .
[297] Henkes Electric Direct at 53-54.
[298] Id. at 54.

amount of the MISO exit fee in the Companies' next base rate case.[299] If the regulatory liability account exceeds the amount of the regulatory asset, the excess would be returned to ratepayers in an appropriate manner.[300]

The Companies accept Mr. Henkes' recommendation, provided that four conditions are met: (1) FERC issues an Order authorizing the Companies' exit from MISO; (2) FERC lawfully establishes the appropriate amount of the MISO exit fee; (3) MISO Schedule 10 charges concurrently cease at the time of the Companies' exit from MISO and incurrence of the exit fee; and (4) revenues associated with the MISO Schedule 10 charges be recorded in a regulatory liability account and will offset the FERC-approved MISO exit fee until the Companies' next base rate proceeding.[301] At the hearing, Mr. Henkes expressed his agreement with the Companies' position.[302]

E. Modifications to adjustments proposed by AG

The AG has recommended several minor modifications to test year expense through the Miscellaneous Expenses Adjustment to the calculation of the revenue requirement for LG&E's electric and gas operations. LG&E only opposes the proposed adjustments relating to employee gifts, award banquets and social expenses. These prudent and reasonable expenses should be charged to ratepayers because they reward employees in connection with the Companies' safety programs and professional achievements or accomplishments. In addition, such expenses contribute to the morale of employees and provide incentives for high levels of performance. Customers benefit from an efficient, motivated workforce. In general, it is not unusual or unreasonable for other companies to incur such expenses.

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[299] Id. at 54.
[300] Id. at 54.
[301] Beer LG&E and KU Rebuttal at 2.
[302] TE, Volume III, at 111-112.

F. The adjusted net operating income of LG&E and KU for the test year includes the appropriate adjustments.

1. LG&E's and KU's electric operations

LG&E calculated its adjusted net operating income found reasonable for electric operations to be $105,781,937 and its pro forma net operating income for electric operations to be $68,010,218.[303] KU calculated its adjusted net operating income found reasonable for electric operations to be $95,564,061 and its pro forma net operating income for electric operations to be $60,965,866.[304]

2. LG&E's gas operations

All the parties, including the AG, in Section 1.2 of the Partial Settlement, Stipulation and Recommendation, have agreed that effective July 1, 2004 the annual increases in revenues for LG&E's gas operations is $11,900,000 for purposes of determining the rates of LG&E's gas operations in rate proceedings. The parties agreed that the additional $11,900,000 produces fair, just and reasonable rates for all gas customers of LG&E.

VI. THE PROPOSED OVERALL RATES OF RETURN ARE REASONABLE.

A. The Companies' capital structures are reasonable.

1. LG&E's capital structure is reasonable

In its application, LG&E proposed an adjusted end-of-test-period capital structure containing 48.4% debt, 3.6% preferred stock and 48% common equity.[305] In response to Commission data requests, LG&E subsequently filed an analysis of its embedded cost of capital to reflect changes through February and March 2004, and updated versions of Rives Exhibit 2 to reflect the changes.[306]

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303 Rives LG&E Direct at Exhibit 7.
304 Rives KU Direct at Exhibit 7.
305 Rives LG&E Direct at Exhibit 2, p. 1 of 2.
306 LG&E Updated Response filed April 29, 2004 to PSC Item No. 43.

LG&E agrees with the Commission's policy of recognizing the impact on capital costs and structure of significant post-test year issues of debt or equity. On April 29, 2004, LG&E updated its capitalization by applying the March 2004 capital structure percentages to the September 2003 per book test year-end capitalization amounts. LG&E used the same capitalization adjustments as originally filed with the exception of MPL. LG&E recorded in its financial statements the transfer of MPL from equity to regulatory asset, in accordance with the FERC ruling, in March 2004. The March 2004 capital structure percentages then reflected the MPL adjustment and a further capitalization adjustment was not needed. LG&E also used the March 2004 annual embedded cost rates on its calculation of the cost of capital.

2. KU's capital structure is reasonable

In its application, KU proposed an adjusted end-of-test-period jurisdictionalized capital structure containing 45.55% debt, 2.39% preferred stock and 52.06% common equity.[307] In response to Commission data requests, KU subsequently filed an analysis of its embedded cost of capital to reflect changes through February and March 2004, and updated versions of Rives Exhibit 2 to reflect the changes.[308]

KU agrees with the Commission's policy of recognizing the impact on capital costs and structure of significant post-test year issues of debt or equity. On April 29, 2004, KU updated its capitalization by applying the March 2004 capital structure percentages to the September 2003 per book test year-end capitalization amounts. KU used the same capitalization adjustments as originally filed with the exception of MPL and Green River retirement. KU recorded in its financial statements the transfer of MPL from equity to regulatory asset, in accordance with the FERC ruling, in March 2004. The March 2004 capital structure percentages then reflected the

[307] Rives KU Direct at Exhibit 2.
[308] KU Updated Response filed April 29, 2004 to PSC Item No. 43.

MPL adjustment and a further capitalization adjustment was not needed. KU also used the March 2004 annual embedded cost rates on its calculation of the cost of capital.

B. The AG's position on reflecting changes to the capital structures is unreasonable.

The AG argues that the Companies' (1) capital cost rates should be updated beyond the test year and before a final decision in these cases, and (2) capital structure ratios should also be updated but only if the changes are minor.[309] To be consistent with past Commission practice, the Companies agree that the cost rates and capital structure ratios should be updated beyond the test year and before a final decision in these proceedings.[310] The Companies do not agree that capital structure ratios should be updated only if the changes are minor. Regardless of whether or not the changes are minor, it is only reasonable to update capital structure ratios if cost rates are also updated since capital structure and cost rates are interdependent.

C. The cost of debt and preferred stock is reasonable.

The Companies' costs and amounts of debt and preferred stock are shown on LG&E's and KU's Rives Exhibit 2. The costs and amounts of these forms of capital are reasonable.

The AG did not contest the amounts or costs of these forms of capital.

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[309] The AG recommends that the revenue conversion factor incorporate the Companies' effective tax rates as opposed to the Companies' incorporation of the Kentucky state income tax rate of 8.25%. For the reasons discussed under the adjustment for federal and state income taxes, the Companies believe that the Commission should reject the AG's recommendation to use the effective Kentucky state income tax rate and accept the Kentucky state income tax rate of 8.25% proposed by the Companies.

[310] Rives LG&E and KU Rebuttal at 5-6.

D. The Companies' proposed returns on common equity are reasonable.

1. Cost of equity recommendations

Two witnesses testified in this proceeding concerning the cost of equity for the electric operations of LG&E and KU.[311] Mr. Robert Rosenberg, testifying on behalf of the Companies, employed four separate approaches to estimate the cost of equity including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM); (3) two risk premium analyses; and (4) a comparable earnings analysis. Mr. Rosenberg determined a cost of equity range of 10.75-11.25 percent and recommended that the Companies be allowed 11.25 percent—at the upper end of the range. Dr. Carl Weaver, testifying on behalf of the AG, employed two DCF calculations, the CAPM approach and a risk premium analysis to determine the cost of equity. In his testimony, Dr. Weaver arrived at a range of 9.75-10.25 percent and recommended an allowed return on equity of 10.0 percent.

As a preliminary matter, it should be noted that Mr. Rosenberg's recommendation comports with the general level of returns being allowed to electric utilities across the country, while Dr. Weaver's recommendation is far below. Electric utilities have been allowed returns that averaged 11 percent both throughout 2003 and, also, in the first quarter of 2004.[312] It is also important for the Commission to note that Dr. Weaver's effective return on equity recommendation is actually much closer to that of Mr. Rosenberg than the nominal 10.0 percent figure that appears in his testimony. Dr. Weaver indicated that he would place the greatest emphasis on his DCF constant-growth analysis, which produced a result of 10.48 percent, or 10.5

[311] Two other witnesses—Mr. Baudino on behalf of the KIUC and Mr. Kincel on behalf of the Department of Defense—also submitted testimony on cost of equity, but those testimonies were withdrawn because those parties became signatories to the Partial Settlement, Stipulation and Recommendation submitted to the Commission.
[312] Rebuttal Testimony of Robert G. Rosenberg of April 26, 2004 (Case Nos. 2003-00433 and 2003-00434) ("Rosenberg LG&E and KU Rebuttal") at 2.

percent rounded.[313] Dr. Weaver indicated that if the ESM were eliminated, he would increase the cost of equity by 25 basis points.[314] Thus, if the 10.5 percent result that Dr. Weaver emphasized is increased by 25 basis points to reflect the discontinuance of the ESM, then Dr. Weaver's effective recommendation would be 10.75 percent. And that 10.75 percent figure is reached even **before** consideration of any of the methodological deficiencies or corrections thereto relating to Dr. Weaver's analyses which are reviewed below. Thus, the Commission is presented with an effective range of cost of equity recommendations in this proceeding of 10.75 percent, per Dr. Weaver adjusted, and 11.25 percent, per Mr. Rosenberg.[315] This range much more closely comports with the 11 percent level of recent allowed returns for electric utilities.

2. Interest rate environment

Interest rates over the past few years have been rather benign, benefiting both customers and the Companies. However, the period of "easy money" is ending and interest rates are beginning their rise. Even Dr. Weaver agreed that "inflation would rear its ugly head once again and interest rates would start to rise."[316] The likelihood of higher interest rates was even acknowledged in the May 5, 2004 *Lexington Herald Leader* which had a headline "Interest Rate Increase Expected."[317] While Dr. Weaver did attempt to reflect the possibility of higher interest rates in the future, his attempt fell short for several reasons. First, Dr. Weaver had even higher interest rate forecasts available to him that he did not employ in his analysis, and use of these

[313] Weaver Direct at 54; TE, Volume III, at 189-190. Note that this 10.5 percent (rounded) result, upon which Dr. Weaver indicates he is going to place the greatest emphasis, is higher than the entire 9.75-10.25 percent cost of equity range that Dr. Weaver determines for the Companies; TE, Volume III, at 191.
[314] Response of AG to PSC Data Request No. 26 (Case No. 2003-00433); TE, Volume III, at 179.
[315] This range is also close to the 10.25-11.25 percent cost of equity range that Dr. Weaver determined for LG&E in his testimony in the ESM proceeding filed in December 2003. As Mr. Rosenberg pointed out, LG&E's risk changed very little since that time, per Dr. Weaver's own evaluation, and interest rates are also virtually unchanged; Rosenberg LG&E and KU Rebuttal at 3-4; TE, Volume II, at 86-87, 91).
[316] TE, Volume III, at 189.
[317] TE, Volume III, at 197.

forecasts would raise his result significantly.[318] Second, Dr. Weaver only employed the yield on 10-year Treasury securities in his analysis. He thought that 10-year Treasury rates were a good representation of long-term rates in general because the yield curve did not rise very steeply beyond ten years.[319] However, now Dr. Weaver has acknowledged that the yield curve is getting steeper and investors are likely expecting rising interest rates.[320] Had Dr. Weaver used Treasury securities of longer maturity than just ten years, his results would have been at least 50-90 basis points higher.[321] Third, actual interest rates have continued their rise even beyond the hearing, as shown in the table below:

Treasury Security	Per Dr. Weaver Testimony (1)	Per Dr. Weaver Cross-Examination (2)	Recent Level (5/19/04) (3)
10-Year	4.05 %	4.56 %	4.79 %
20-Year	Not Used	5.34	5.54
Long Term	Not Used	5.38	5.55

(1) Weaver Exhibit, Schedule 39.
(2) TE, Volume III, 192-193 and 196
(3) *Selected Interset Rates*, H.15, May 20, 2004, www.federalreserve.gov

While the Companies do not believe that the Commission should rely exclusively on recent spot interest rates in forming its conclusions in this proceeding, the Commission should be

318 Rosenberg LG&E and KU Rebuttal at 4-5.

319 Response of AG to Staff Data Request No. 25; TE, Volume III, at 195. The "yield curve" is a plotting of Treasury security yields of different maturities (*e.g.*, 3 months, 6 months, 1 year, 10 years, 20 years, etc.). A "flat yield curve" means that investors require the same yield on both short-term and long-term Treasury securities, which suggests that investors do not expect inflation to change. Conversely, a relatively steep yield curve means that investor require a higher yield on Treasury securities of longer duration, which implies that investors expect inflation to increase substantially in the future.

320 TE, Volume III, at 196.

321 Rosenberg LG&E and KU Rebuttal at 18; TE, Volume III, at 196-197.

cognizant of the recent and likely continued rise in interest rates when the allowed return level is established in this proceeding. This interest rate environment provides a rational basis to choose a figure at the upper end of the cost of equity ranges determined in this proceeding given the likely trends in capital costs in the near future.

3. Proxy Group Selection

Because the Companies, themselves, are not publicly traded, Mr. Rosenberg employed a proxy group of companies in order to estimate the Companies' cost of equity. Companies were chosen for the proxy group if they appeared in *The Value Line Investment Survey* Electric Utility category, had senior bond ratings of Aa/A from Moody's and AA/A from Standard & Poor's, were not involved in any major merger activity, did not have significant unregulated operations and if their dividend payment was secure. On the basis of these criteria, Mr. Rosenberg selected 13 comparison companies for his electric proxy group. Although Dr. Weaver suggested that Mr. Rosenberg should have deleted three companies from his proxy group, Mr. Rosenberg indicated that elimination of those three companies would have no effect on his recommendation.[322] In contrast to Mr. Rosenberg's straightforward selection criteria for the proxy group, Dr. Weaver used an elaborate process which was rather arbitrary in selecting his companies. For example, Dr. Weaver included one company with a 39.8 percent common equity ratio, but excluded another company with a 37.6 percent common equity ratio.[323]

4. The DCF approach

The chief inputs needed for a DCF calculation include the price, which is included in the dividend yield, and an estimate of the growth that investors expect for a company. Conditions in the electric utility industry currently make expected growth more difficult to estimate than was

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[322] Rosenberg LG&E and KU Rebuttal at 8.
[323] TE, Volume III, at 186.

previously the case. While growth projections made by the analysts are typically made only for the next five years, given the flux and turmoil in the electric utility industry, Mr. Rosenberg conducted a two-stage DCF calculation where he allowed for the potential that growth over the long run might be somewhat different than that forecasted for the near term. For near-term growth, Mr. Rosenberg used the average of forecasts made by Value Line and First Call. For long-term growth, Mr. Rosenberg used three estimates—an estimate of expected long-run growth in GDP,[324] an estimate of sustainable growth[325] (based on Value Line projections for retention growth and growth from stock issuances) and the average projection of growth for the electric utility industry. These DCF calculations produced results in the range of 10.00-10.75 percent.[326]

Dr. Weaver performed both constant-growth and multi-stage growth DCF analyses. The constant-growth DCF model showed a sharp change in results between the filing of Dr. Weaver's ESM and rate case testimonies—the differential not being supported by any change in risk of LG&E or in interest rates.[327] Mr. Rosenberg showed that Dr. Weaver's multi-stage DCF analysis was understated by up to 2 percentage points due to various deficiencies.[328]

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[324] It was suggested to Mr. Rosenberg that he should have employed a forecast of GDP growth made by the Conference Board. However, Mr. Rosenberg indicated that the calculation of GDP growth that he used in his analysis encompassed a much longer forecast period than that made by the Conference Board. TE, Volume II, at 97-98. Dr. Weaver had also suggested that Mr. Rosenberg should not have employed the CPI forecast of inflation in his calculation of nominal GDP growth. However, Mr. Rosenberg showed that the CPI is a widely-used measure of inflation—in fact, it is even used by Dr. Weaver, himself. Rosenberg LG&E and KU Rebuttal at 15-16.

[325] Dr. Weaver criticized Mr. Rosenberg for deleting the CH Energy sustainable growth cost of equity estimate from his analysis. Mr. Rosenberg did so because that cost of equity estimate was barely above the level of utility bond yields and CH Energy's price was strongly affected by takeover speculation. TE, Volume II, at 102-103. Dr. Weaver, himself, used judgment in excluding what he thought was an unreasonable estimate from his analyses. TE, Volume III, at 180-183.

[326] Rosenberg LG&E Direct at 24; Rosenberg KU Direct at 21.

[327] Rosenberg LG&E and KU Rebuttal at 3-4; TE, Volume II, at 91.

[328] Rosenberg LG&E and KU Rebuttal at 9-13. Dr. Weaver agreed with one of the changes to his multi-stage DCF approach made by Mr. Rosenberg but did not comment on the other corrections. TE, Volume III, at 173. These corrections resulted in an adjusted multi-stage DCF result of as high as 10.79 percent.

5. The CAPM approach

Mr. Rosenberg employed two separate formulations of the CAPM approach—the "traditional" CAPM formulation and an "empirical"[329] CAPM formulation. Three inputs are needed for a CAPM analysis—beta, the risk-free rate and the expected market risk premium. For beta, Mr. Rosenberg took the average of the figures reported by Value Line for his proxy companies. For the risk-free rate, Mr. Rosenberg employed both the recent average of yields on long-term Treasury bonds and yields on Treasury bond futures. For the expected market risk premium, Mr. Rosenberg used two estimates—one based on historic data taken from a well-known publication by Ibbotson Associates[330] and a second using a DCF calculation for the S&P 500. Using the Ibbotson risk premium, Mr. Rosenberg derived cost of equity estimates in the range of 9.6-10.2 percent. Using the S&P-based risk premium, Mr. Rosenberg calculated cost of equity estimates of 11.3-12.2 percent. Since there was evidence that indicated that the CAPM will understate the cost of equity for smaller companies, Mr. Rosenberg added a size premium[331] to the above-reported results and reached an overall range of 10.75-11.50 percent from the CAPM method.

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[329] Dr. Weaver made two criticisms of the empirical CAPM formulation, both of which are incorrect. Dr. Weaver claimed that the empirical formulation used by Mr. Rosenberg suffers from multicollinearity. [Multicollinearity is a condition of a regression equation that has two independent variables which are highly correlated.] Mr. Rosenberg performed no regression analysis for the empirical CAPM approach and thus, the criticism is inapposite—it cannot exist in Mr. Rosenberg's approach. Second, referencing an article by Professor Black, Dr. Weaver claimed that the empirical CAPM results in a double adjustment to beta. However, Mr. Rosenberg clearly indicated that he did not rely on the Black article, that it had no relation to his testimony and that there is no double count of beta by using the empirical CAPM formulation. Rosenberg LG&E and KU Rebuttal at 25-26; TE, Volume II, at 108-109.

[330] In using the historic data from the Ibbotson publication, Mr. Rosenberg employed the arithmetic average of past results as a proxy for the future. This approach is supported both by the Ibbotson source, itself, and by a text by Professor Morin. Dr. Weaver suggested the geometric average should be used instead. However, Mr. Rosenberg clearly demonstrated that while the geometric average might be appropriate for calculating past, certain results, it was not appropriate for calculating expectations for the future. Rosenberg LG&E and KU Rebuttal at 20-22.

[331] Dr. Weaver questioned the appropriateness of the size premium. However, Ibbotson research shows that small companies have earned higher returns than estimated by the CAPM, indicating that the CAPM approach is not capturing a systematic factor related to small companies. Rosenberg LG&E and KU Rebuttal at 25. In this regard it is important to note that the Commission at page 63 of its Order in the prior LG&E gas rate proceeding, Case No. 2000-080, criticized Dr. Weaver for not including a size premium in his analysis.

Dr. Weaver performed numerous CAPM calculations, reaching a result of only 9.64 percent.[332] Dr. Weaver's CAPM analysis is substantially understated because of his use of understated yields on 10-year Treasury securities and the failure to use the yields on longer-term Treasury yield securities, both topics discussed earlier in this brief. In addition, Dr. Weaver very substantially understated one of his calculations of the expected market risk premium. Correcting that under-estimate raised Dr. Weaver's CAPM result by about 135 basis points.[333]

6. The Risk Premium approach

Mr. Rosenberg employed two risk premium calculations. The first calculation measures the historic average spread between returns on utility stocks versus utility bonds. Mr. Rosenberg found that the historic average spread equaled 4.29 percent. He added this average spread to the recent A utility bond yield of 6.52 percent to obtain a cost of equity estimate of 10.81 percent. The second risk premium approach uses a regression analysis to determine the relationship between risk premiums (as determined using rates of return allowed by regulatory commissions) and the level of interest rates.[334] Using the recent level of interest rates, Mr. Rosenberg calculated a risk premium of 4.34 percent which, when added to the recent A bond yield of 6.52 percent, produced a risk premium cost of equity estimate of 10.86 percent.

Dr. Weaver also performed a risk premium analysis, but reached his average risk premium in an unconventional and counter-intuitive way. For example, Dr. Weaver weighted

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[332] TE, Volume III, at 174.
[333] Rosenberg LG&E and KU Rebuttal at 24.
[334] Dr. Weaver made two criticisms of this risk premium approach. First, he claimed that the model had a high R^2 (*i.e.*, the measure of goodness of fit of the data) due to the supposed presence of autocorrelation. Mr. Rosenberg performed an analysis to eliminate any effect of autocorrelation and found that the revised model had exactly the same R^2 and the estimated risk premium was 1 basis point higher. Rosenberg LG&E and KU Rebuttal at 29-30. Second, Dr. Weaver claimed that the risk premium regression should not show an inverse relationship between interest rates and the risk premium. While Dr. Weaver opined that the data should not show an inverse relationship, both Mr. Rosenberg's risk premium analysis and Dr. Weaver's risk premium analyses showed that an inverse relationship did, in fact, exist. Rosenberg LG&E and KU Rebuttal at 30-32. Mr. Rosenberg provided a reasonable explanation for the observed inverse relationship in response to AG Data Request No. 110 (Case No. 2003-00433.)

the return achieved in the 1992-1993 period eleven times more than the return achieved in the 2002-2003 period. Using more intuitive methods of averaging, Mr. Rosenberg obtained risk premium results between 50 and 90 basis points higher than calculated by Dr. Weaver.[335]

7. The Comparable Earnings approach

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the criteria set forth by the Supreme Court in the *Bluefield* and *Hope* decisions. Using companies with a Value Line Safety Rank of 2,[336] Mr. Rosenberg determined that returns earned by these companies over recent historic periods and projected for the future were in the range of 14.0-14.5 percent.

8. Summary concerning the return on equity to be allowed

Based on the four methods employed by Mr. Rosenberg, he concluded that the cost of equity for the proxy group of electric companies used in his analysis is in the range of 10.75-11.25 percent. Mr. Rosenberg noted that given the difficulty of determining the cost of equity with exact precision, regulatory commissions often estimate a "range of reasonableness" for the return on equity and then use qualitative factors and judgment to determine where within this range a particular allowed return should be set. He recommended that the electric operations of LG&E and KU be allowed a return at the upper end of the 10.75-11.25 percent cost of equity range for the proxy group. As a basis for this recommendation, Mr. Rosenberg cited the Companies' efficient operations and the uncertain business climate for utilities that exists currently. As additional support for allowing the upper end of the range, Mr. Rosenberg, in a prescient comment, noted that upward changes in interest rates were more likely than downward

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[335] Rosenberg LG&E and KU Rebuttal at 27-28.

[336] The proxy group employed by Mr. Rosenberg had a median Safety Rank of 2. Value Line defines the safety rank as a measure of the total risk of a stock and describes the safety rank as one of the main criteria investors should consider in selecting stocks. Rosenberg LG&E Direct at 47-48; Rosenberg KU Direct at 44-45.

changes. Thus, Mr. Rosenberg concluded that LG&E's electric operation and KU should be allowed a return on equity of 11.25 percent in this proceeding.

In contrast to Mr. Rosenberg's well-reasoned approaches, Dr. Weaver's analyses suffer from both theoretical and empirical deficiencies that cause his results to be substantially understated. As noted earlier in this brief, even before correcting any errors in Dr. Weaver's analysis, his effective recommendation in this proceeding is 10.75 percent. Considering the various other understatements in his analysis and the very substantial recent rise in interest rates and likely continued rise in interest rates, the Commission should allow the electric operations of LG&E and KU an 11.25 percent return on equity in this proceeding.

VII. THE PROPOSED REVENUE ALLOCATION AMONG CUSTOMER CLASSES IS REASONABLE.

Pursuant to Section 10(6)(u) of 807 KAR 5:001, the Companies submitted cost of service studies as part of their Filing Requirements in the rate proceedings. The studies, conducted by The Prime Group, LLC, were filed as exhibits to the direct testimony of Mr. Seelye, Senior Consultant and Principal of The Prime Group. Mr. Seelye and The Prime Group have previously prepared embedded cost of service studies that have been accepted and approved by the Commission.[337] The cost of service methodology utilized here is the same as that which was approved in those cases. Specifically, the Prime Group conducted a fully allocated, embedded cost of service study for LG&E's gas service.[338] It also prepared fully allocated, time differentiated, embedded cost of service studies for LG&E's electric operations and for KU's

[337] Seelye LG&E Direct at 9; *see also In the Matter of: Application of Louisville Gas and Electric Company to Adjust its Gas Rates and to Increase its Charges for Disconnecting Service, Reconnecting Service and Returning Checks*, Case No. 2000-080, Order dated September 27, 2000, at 66-67; *In the Matter of: Adjustment of the Rates of Delta Natural Gas Company, Inc.*, Case No. 99-176, Order dated December 27, 1999, at 36.
[338] Seelye LG&E Direct at 9.

operations.[339] Mr. Seelye supported the cost of service studies in his testimony, and provided detailed discussion of the allocations being proposed by LG&E and KU based on those studies.[340] At the same time, however, the Companies considered other ratemaking principles such as customer acceptance, gradualism and the need to maintain price stability by avoiding overly disruptive changes in rate design which counsel toward a tempered movement towards a full cost-of-service result.[341]

As part of the settlement negotiations in this case, all parties to the rate cases reached an agreement on a percentage allocation of the annual revenue increase for the Companies' operations.[342] That unanimous agreement is consistent with the ratemaking principles of customer acceptance, gradualism and the need to maintain price stability, is a meaningful reduction in the subsidization of the residential and lighting classes, and is a fair, just and reasonable resolution of the issue of how the Companies' revenue increases should be allocated to ratepayers.

VIII. THE PROPOSED RATE DESIGNS ARE REASONABLE AND SHOULD BE APPROVED.

The Companies were also guided by the cost of service study prepared by The Prime Group in developing the proposed rate designs in these proceedings. The Companies have proposed rate designs which transition toward a true reflection of the cost of providing service, while also achieving a better balance between the class rates of return.[343] Based on the cost-of-service study and a review of LG&E's and KU's tariffs, the Companies proposed numerous

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[339] Id. at 42; Seelye KU Direct at 9. Prior to conducting the KU cost of service study, Mr. Seelye and The Prime Group conducted a jurisdictional separation study utilizing the same methodology accepted by the Commission in KU's last general rate case. Seelye KU Direct at 8-9.
[340] Seelye LG&E Direct at 10, *et. seq.*; Seelye KU Direct at 10, *et. seq.*
[341] Beer LG&E Direct at 10; Beer KU Direct at 8.
[342] Partial Settlement, Stipulation and Recommendation at Sections 2.1, 2.2 and Exhibit 1.
[343] Beer LG&E Direct at 10; Beer KU Direct at 8; Seelye LG&E Direct at 57; Seelye KU Direct at 29-30.

changes in their respective rate schedules, structures and design thereof, miscellaneous charges and terms and conditions of service.

In keeping with their transition to rate designs which accurately reflect the cost of providing service, the Companies proposed to eliminate their current block rate structures for residential electric customers. Specifically, LG&E proposed the elimination of its summer inverted-block rate, and both Companies proposed to eliminate their winter declining-block rates, because analyses showed that continued use of these rate structures is not justified.[344] The Companies instead proposed the implementation of a flat energy charge. Such a charge is more reflective of the cost of providing service, is easier for the customer to understand, and will decrease the volatility in customer bills during the summer months when usage is higher because of air-conditioning requirements.[345]

Through this proceeding, the Companies also seek to add or revise several miscellaneous non-recurring charges. The Companies request an increase in the disconnect/reconnect charge for LG&E electric, LG&E gas, and KU electric customers. KU proposes to withdraw its after-hours reconnect charge and to increase its returned payment fee and meter test charge.[346] LG&E proposes to increase its third-trip gas inspection charge and to add a meter test charge.[347]

Finally, the Companies have proposed a number of changes to better harmonize their tariffs, simplify the language contained in their existing tariffs and eliminate redundancy in order to allow some business processes to run more efficiently.

As set forth in Section 3.23 of the Partial Settlement, Stipulation and Recommendation, each party to these proceedings has agreed to the rate designs proposed by the Companies unless

[344] Seelye LG&E Direct at 3-4; Seelye KU Direct at 2-3.
[345] Seelye LG&E Direct at 4; Seelye KU Direct at 2.
[346] Cockerill KU Direct at 3-4.
[347] Cockerill LG&E Direct at 3-4, 6-7.

modified therein (*e.g.*, Sections 3.8 - 3.13). These proposed rate designs are reasonable and should be approved by the Commission. This brief will now review some of the more significant rate proposals.

A. <u>Changes to KU Rate Schedules.</u>

1. Residential Service Schedule RS

KU's Residential Service Rate ("Rate RS") is a two-part rate consisting of a customer charge and an energy charge.[348] The energy charge is structured as a declining-block rate.[349] In this case, KU is proposing to eliminate the block rate structure for residential service and use a flat energy charge instead.[350] A flat energy charge is more reflective of the cost of providing service and is easier for customers to understand.[351] Furthermore, with a higher customer charge, there is less need to retain the declining-block rate structure.[352] Under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a customer charge of $5.00 per month would be reasonable.[353]

KU is also proposing to eliminate the Full Electric Residential Service Rate ("Rate FERS") because the cost structures and unit charges of Rate RS and Rate FERS are so similar that there is no valid justification for maintaining two separate rates.[354] Consequently, KU is proposing to eliminate Rate FERS and move the customers served under Rate FERS to Rate RS.[355]

While KU is proposing to limit future service under Rate RS to single phase service, customers already receiving three phase service under this rate schedule will continue to be

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348 Seelye KU Direct at 33.
349 <u>Id</u>.
350 <u>Id</u>. at 39.
351 <u>Id</u>.
352 <u>Id</u>.
353 Partial Settlement, Stipulation and Recommendation at Section 3.9.
354 Seelye KU Direct at 40.
355 <u>Id</u>.

served under Rate RS.[356] In addition, the availability of service description has been simplified, a reference to the terms and conditions for service has been added and the minimum demand charge has been deleted.[357]

2. Volunteer Fire Department Rate VFD

Volunteer Fire Department Rate ("Rate VFD") currently contains the same charges as Rate FERS.[358] Because Rate FERS is being eliminated and the customers moved to Rate RS, Rate VFD will be modified to match the rates being proposed for Rate RS.[359] Under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a customer charge of $5.00 per month would be reasonable.[360]

3. Combined Off-Peak Water Heating Rider CWH

Combined Off-Peak Water Heating Rider ("Rate CWH") is an old promotional water-heating rate that is no longer justified.[361] The number of customers served under this rate schedule has been declining steadily for a number of years.[362] As a result, KU is proposing to consolidate this schedule with Rates RS and GS, as applicable.[363] Customers currently served under this rate schedule would take service under either Rate RS or Rate GS.[364]

4. General Service Rate GS

KU is proposing to eliminate the declining-block rate structure and increase the customer charge in the General Service Rate ("Rate GS").[365] Under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a customer charge of $10.00 per

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356 Id.
357 Id.
358 Id.
359 Id.
360 Partial Settlement, Stipulation and Recommendation at Section 3.9.
361 Seelye KU Direct at 41.
362 Id.
363 Id.
364 Id.
365 Id.

meter per month would be reasonable.[366] Ideally, all customers should be served under a three-part rate consisting of a customer charge, demand charge and energy charge.[367] A three-part rate more properly reflects the principal cost drivers of utilities – namely number of customers served, maximum demand and the amount of energy used.[368] However, the higher cost of installing metering equipment to measure demands has prohibited the implementation of three-part rates on a wider scale.[369] As a result, the parties have unanimously agreed that availability of future service under this rate schedule should be limited to secondary service at maximum loads no greater than 500 kW per month.[370]

KU is proposing to eliminate the Electric Space Heating Rider Rate 33 and merge it with Rate GS because it is an old promotional rate that is no longer justified.[371] There are relatively few customers served under this rate.[372] Any existing customers are served under Rate GS for their non-space heating usage and thus, KU is proposing that their space heating usage will also be billed on Rate GS in the future.[373]

5. Large Power Rate LP

KU is proposing to implement a customer charge and eliminate the declining-block structure of the energy charge for Large Power Rate ("Rate LP").[374] KU is also proposing to recover more fixed costs through the demand charge rather than continue to recover a portion of demand-related fixed costs through the energy charge.[375] In this rate schedule, KU has also eliminated redundant or unnecessary language and limited single-phase service to a minimum

[366] Partial Settlement, Stipulation and Recommendation at Section 3.9.
[367] Seelye KU Direct at 41.
[368] Id. at 41-42.
[369] Id. at 42.
[370] Partial Settlement, Stipulation and Recommendation at Section 3.10.
[371] Seelye KU Direct at 42.
[372] Id.
[373] Id.
[374] Id.
[375] Id.

average of 200 kW.[376] All service under this rate schedule will remain limited to a maximum average of 5000 kW.[377]

KU is proposing to eliminate High Load Factor Rate HLF and Water Pumping Rate M and merge them into Rate LP as well.[378] Neither of these schedules is used to serve many customers, and KU wants to simplify its rates, eliminate some of its specialized schedules, and combine rates that serve customers of similar size.[379]

6. Large Industrial/Commercial Time of Day Rate LCI-TOD

For its Large Industrial/Commercial Time of Day Rate LCI-TOD, KU is proposing to implement a customer charge and to recover more fixed costs through the demand charge rather than through the energy charge.[380] KU has also proposed deleting the limiting reference to large commercial/industrial customers, eliminating redundant or unnecessary language, and adding language regarding the determination of maximum load under the schedule.[381]

7. Large Mine Power Time of Day Rate LMP-TOD

The hours during the peak period of KU's time-of-day rates are the same in the winter as they are during the summer.[382] Consistent with the costing periods identified in its cost of service study, KU is proposing different hours for the summer billing months of June through September than for the winter billing months of October through May.[383] The peak period will be reduced by 3 hours during the summer months.[384] The shorter peak period during the summer

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376 Id.
377 Id.
378 Id.
379 Id. at 42-43.
380 Id. at 43.
381 Id.
382 Id.
383 Id.
384 Id.

billing months should provide large commercial and industrial customers with slightly greater opportunity to shift load to off-peak periods.[385]

8. Curtailable Service Rider CSR

The parties have agreed to several major changes to KU's Curtailable Service Rider ("CSR"). Those changes are discussed in detail in Sections 3.20 and 3.21 of the Partial Settlement, Stipulation and Recommendation.

9. Lighting Rates

KU has eliminated redundant or unnecessary language, eliminated reference to five lights which are no longer used by customers, and restricted certain mercury vapor lights.[386] KU is also proposing to merge the Decorative Street Lighting Rate Dec. St. Lt. into Street Lighting Service Rate St. Lt. so that there will be only one rate schedule applicable to street lighting.[387] KU is also eliminating redundant or unnecessary language contained in Private Outdoor Lighting Rate (P.O.Lt.).[388]

Additionally, KU is proposing to eliminate Customer Outdoor Lighting Rate C.O.Lt. and move the customers to Rate P.O.Lt so that all outdoor lighting will be served by a single rate schedule.[389] The lights being eliminated are inefficient and used by very few customers.[390]

10. Rider for Intermittent and Fluctuating Loads ("IFL")

KU is proposing that the Rider for Intermittent and Fluctuating Loads be added to address concerns about loads which have a detrimental effect on the system, and thus, potentially adversely affect other KU customers or facilities.[391]

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385 Id.
386 Id. at 45-46.
387 Id. at 46.
388 Id.
389 Id.
390 Id.
391 Id.

11. Excess Facilities Rider

KU is proposing to implement an Excess Facilities rider to standardize its practices and offerings across the Companies.[392] KU has a widely-used facilities lease arrangement that is similar in purpose to LG&E's Excess Facilities rider.[393] If a customer on KU's system required non-standard facilities (such as a second back-up feed or automatic switchgear) or wanted to lease transformers from the utility to take service at a lower voltage, KU's long-standing practice was to lease the facilities to the customer at an annual lease rate of 28% of the cost of the facilities.[394] The lease payment was intended to cover the carrying costs on the investment, depreciation, and operation and maintenance expenses.[395] The payment continued for as long as the customer required the facilities and, in effect, provided for the eventual replacement of the facilities by applying a straight carrying charge methodology (as opposed to a levelized carrying charge methodology).[396] KU has been offering lease arrangements since at least the early 1980s and has numerous such arrangements with customers.[397]

KU is proposing to separate the Excess Facilities Rider into two components: (i) a carrying charge component and (ii) an operating expenses component.[398] For KU, the carrying charge component for distribution facilities would be 0.94% per month as applied to the original cost of the facilities, and the operating expenses component would be 0.56%.[399] The carrying charge component would cover the utility's cost of capital, grossed up for income taxes related to the investment.[400] The operating expenses component would cover the operation and

392 Id.
393 Id.
394 Id.
395 Id. at 46-47.
396 Id. at 47.
397 Id.
398 Id.
399 Id.
400 Id.

maintenance expenses, property taxes and the cost of replacing the facilities.[401] A customer can choose either to pay for the facilities up front through a contribution in aid of construction or pay the carrying charge set forth in the rate.[402] If a customer chooses to make a contribution in aid of construction for the facilities, then only the operating expenses component of the rate, or 0.56%, would apply.[403] If a customer does not want to pay for the facilities up front, then both the carrying charge component and the operating expenses component would apply.[404] In either case, the utility would be responsible for replacing the facilities should the facilities fail.[405]

12. Redundant Capacity Rider

The purpose of KU's Redundant Capacity rider is to allow customers that have one or more redundant feeds to reserve back-up capacity on the distribution system.[406] As customers come to rely on greater use of electric technology, there is more and more customer interest in having a redundant feed, along with automatic relay equipment capable of switching from a principal circuit to a backup circuit, in the event that electric service from the primary feed is lost.[407] With the greater use of technology, some customers are finding it increasingly difficult to tolerate electrical outages for even short periods of time.[408] A customer who wants a second feed must pay the cost of the customer-specific facilities required to provide the feed, including the second distribution line, automatic relay equipment or other customer-specific facilities that may be required.[409]

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401 Id.
402 Id.
403 Id.
404 Id. at 47-48.
405 Id. at 48.
406 Id.
407 Id.
408 Id.
409 Id. at 48-49.

Customers can pay for the customer-specific facilities by either making a contribution in aid of construction or by taking service under the Excess Facilities rider.[410] If the customer wants to have full backup capacity on the second feed, there are additional costs incurred by KU to ensure that there is sufficient network distribution capacity to provide full backup in the event that a relay occurs on the automatic switchgear.[411] KU must plan the distribution facility as if there were two customers placing demands on the system.[412] For this reason, KU is proposing to implement a demand charge to cover the distribution demand-related cost of providing backup service for new customers with redundant feeds.[413] The demand charge would be applied to the customer's monthly billing demand determined under the standard rate schedule under which the customer receives electric service.[414] The proposed demand charge for primary voltage customers is $0.63 per kW per month of billing demand and the proposed demand charge for secondary voltage customers is $0.80 per kW per month of billing demand.[415]

B. Changes to LG&E Electric Rate Schedules.

1. Residential Service

LG&E's current Residential Rate R is a two-part rate consisting of a customer charge and a seasonally-differentiated energy charge.[416] The energy charge is higher in the summer and lower in the winter, and also presently consists of a declining-block rate structure during the winter months and an inverted-block rate structure during the summer months.[417] LG&E is proposing several changes to Rate R, including changing the name of that tariff to Rate RS in order to conform to KU's standard residential rate and eliminating the blocked-rate structure for

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410 Id. at 49.
411 Id.
412 Id.
413 Id.
414 Id.
415 Id.
416 Seelye LG&E Direct at 61.
417 Id.

this tariff, and using a flat energy charge instead.[418] Under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a customer charge of $5.00 per month would be reasonable.[419] The parties have further agreed that LG&E should eliminate the seasonal rate structure for Rate RS and shall implement a non-seasonally differentiated rate structure for Rate RS.[420]

2. Residential Prepaid Metering Pilot Program Rate RPP

The parties have unanimously agreed that LG&E will phase out its PAYG program by limiting the program to existing customers and by removing those meters from existing customers as requested, as meters fail, or as customers move off of the system. LG&E reserved the right to completely terminate the program upon sixty days advance notice to the Commission. In the interim, LG&E is proposing to modify the base rates set forth in its Residential Prepaid Metering Pilot Program to correspond to the average rate for service under Rate RS.[421] The basic customer charge set forth in the rate will similarly be increased from $3.31 to $5.00 per meter per month.[422]

3. Volunteer Fire Department Rate VFD

Rate VFD currently contains the same charges as Rate RS, and LG&E is proposing changes to VFD to match the increase requested for Rate RS.[423]

4. Water Heating Rider

LG&E's Water Heating Rider has been frozen since August 20, 1974, and the cost of service study indicates an extremely low rate of return for this customer class.[424] LG&E is

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418 Id. at 68.
419 Partial Settlement, Stipulation and Recommendation at Section 3.9.
420 Partial Settlement, Stipulation and Recommendation at Section 3.13
421 Seelye LG&E Direct at 69.
422 Id; Partial Settlement, Stipulation and Recommendation at Section 3.9.
423 Seelye LG&E Direct at 69.
424 Id.

proposing to consolidate this rate with Rates RS and GS, so that customers presently being served under the Water Heating Rider would instead take service under Rates RS or GS, as applicable.[425]

5. General Service Rate GS

LG&E is not proposing any changes to the rate structure of Rate GS. However, under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a customer charge of $10.00 per electric single phase meter per month and a customer charge of $15.00 per electric three phase meter per month would be reasonable.[426] Additionally, Rate GS should be available to electric customers with connected loads up to 500 kW. Customers already receiving primary service under this rate schedule as of its effective date will continue to be served under this schedule.[427] LG&E is proposing to limit this service because customers should be served on a rate schedule that provides the appropriate price signals through demand and energy charges.[428] LG&E is also proposing to eliminate the minimum bill for three-phase service.[429]

LG&E is also proposing to eliminate its General Service Space Heating Rider and merge its small number of customers into Rate GS.[430] This is an old promotional rate, and the seasonal rate structure for Rate GS obviates the need for this rider.[431] Under Section 3.12 of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that LG&E will not bill an additional customer charge to Rate GS customers formerly taking service under the Rider for Electric Space Heating Service under Rate GS.

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425 Id.
426 Partial Settlement, Stipulation and Recommendation at Section 3.9.
427 Id. at 70.
428 Id.
429 Id.
430 Id.
431 Id.

6. Large Commercial Rate LC and Large Commercial Time-of-Day Rate LC-TOD

LG&E's LC and LC-TOD rates are designed to have the same underlying charges, except LC-TOD is time-differentiated.[432] LG&E is not proposing to change the basic structure of these rates, but is seeking to adjust the energy, customer and demand charges.[433] LG&E has also proposed to clarify that where regulations require a separate circuit for exit or emergency lighting, the demand and usage of the separate circuit may be combined for billing purposes with those of the principal power circuit.[434] LG&E is also proposing to limit the availability of future alternating current service under Rate LC-TOD to those customers whose monthly demand is 2000 kW or greater and whose entire lighting and power requirements are purchased at a single service location,[435] and to modify the time periods applicable to Rate LC-TOD.[436]

7. Industrial Power Rate LP and Industrial Power Time-of-Day Rate LP-TOD

As with Rates LC and LC-TOD, Rates LP and LP-TOD are designed to have the same underlying charges, except Rate LP-TOD is time-differentiated.[437] LG&E is not proposing to change the basic structure of Rates LP and LP-TOD, but has proposed to lower the energy charge and to increase the customer and demand charges.[438] LG&E has also proposed language in the LP tariff to address a customer's ability to opt-out of the DSM Cost Recovery Mechanism.[439] In addition, LG&E is proposing to limit the availability of future three-phase

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[432] Id. at 71.
[433] Id.
[434] Id.
[435] Id. at 71-72.
[436] Id. at 72.
[437] Id.
[438] Id.
[439] Id.

power and lighting service under Rate LP-TOD to customers with monthly demand of 2000 kW or greater, and to modify the time periods applicable to Rate LP-TOD.[440]

8. Interruptible Service Rider

The parties have agreed to several major changes to LG&E's Interruptible Service Rider. To begin with, LG&E will change the name of the rate to Curtailable Service Rider ("CSR") to harmonize it with KU's tariff.[441] Additional changes are discussed in detail in Sections 3.20 and 3.21 of the Partial Settlement, Stipulation and Recommendation.

9. Supplemental or Standby Service Rate

LG&E's Supplemental or Standby Service Rate is available for customers with their own generation who want to purchase back-up generation, transmission and distribution capacity from the Company.[442] LG&E is proposing to increase the demand charge for this rate to $6.25/kW.[443]

10. Lighting Rates

LG&E is proposing to freeze Rates OL and PSL, which are outdated and do not accurately reflect the variety or the current cost of lights offered by the Company, and to offer prospective customers a new lighting service, Lighting Service Rate LS.[444] This new rate will more accurately reflect the cost of service by including three cost components: the carrying costs plus operation and maintenance expenses applied to the total installed cost of the lighting equipment; the demand- and energy-related cost of serving the light; and the customer-related

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440 Id.
441 Id. at 74.
442 Id. at 76.
443 Id.
444 Id.

cost of serving the light.[445] Under the terms of the Partial Settlement, Stipulation and Recommendation, LG&E's lighting rates would be increased by approximately 7.52%.[446]

11. Rider for Intermittent and Fluctuating Loads

LG&E is proposing that the Rider for Intermittent and Fluctuating Loads ("IFL") be added to address concerns about loads which have a detrimental effect on the system, thus potentially adversely affecting other LG&E customers or facilities.[447]

12. Excess Facilities Rider

LG&E is proposing to change its Excess Facilities Rider to standardize its practices and offerings across both Companies. LG&E is proposing to separate the Excess Facilities Rider into two components: (i) a carrying charge component and (ii) an operating expenses component.[448] The carrying charge component for distribution facilities would be 0.93% per month as applied to the original cost of the facilities, and the operating expenses component would be 0.68%.[449] The carrying charge component would cover the utility's cost of capital, grossed up for income taxes related to the investment.[450] The operating expenses component would cover the operation and maintenance expenses, property taxes, and the cost of replacing the facilities.[451] A customer can choose either to pay for the facilities up front through a contribution in aid of construction or pay the carrying charge set forth in the rate.[452] If a customer chooses to make a contribution in aid of construction for the facilities then only the operating expenses component of the rate, or 0.68%, would apply. If a customer does not want to pay for the facilities up front, then both the carrying charge component and the operating

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445 Id. at 77.
446 Partial Settlement, Stipulation and Recommendation at LG&E Electric Exhibit 1, p. 1 of 27.
447 Seelye LG&E Direct at 77.
448 Id.
449 Id. at 79.
450 Id. at 79-80.
451 Id. at 80.
452 Id.

expenses component would apply.[453] In either case, LG&E would be responsible for replacing the facilities should the facilities fail. This approach is more straightforward, more accurately represents actual costs, and is better suited to meet customer needs.[454]

13. Redundant Capacity Rider

The purpose of the Redundant Capacity Rider is to allow customers that have one or more redundant feeds to reserve back-up capacity on the distribution system.[455] As customers come to rely on greater use of electric technology, there is more and more customer interest in having a redundant feed, along with automatic relay equipment capable of switching from a principal circuit to a backup circuit, in the event that electric service from the primary feed is lost.[456] With the greater use of technology, some customers are finding it increasingly difficult to tolerate electrical outages for even short periods of time.[457] A customer who wants a second feed must pay the cost of the customer-specific facilities required to provide the feed, including the second distribution line, automatic relay equipment, or other customer-specific facilities that may be required.[458]

Customers can pay for the customer-specific facilities by either making a contribution in aid of construction or by taking service under the Excess Facilities Rider.[459] If the customer wants to have full backup capacity on the second feed, there are additional costs incurred by LG&E to ensure that there is sufficient network distribution capacity to provide full backup in the event that a relay occurs on the automatic switchgear.[460] LG&E must plan the distribution

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[453] Id.
[454] Id.
[455] Id. at 81.
[456] Id.
[457] Id.
[458] Id.
[459] Id.
[460] Id. at 81-82.

facility as if there were two customers placing demands on the system.[461] For this reason, LG&E is proposing to implement a demand charge to cover the distribution demand-related cost of providing backup service for new customers with redundant feeds.[462] The demand charge would be applied to the customer's monthly billing demand determined under the standard rate schedule under which the customer receives electric service.[463] The proposed demand charge for primary voltage customers is $1.06 per kW per month of billing demand and the proposed demand charge for secondary voltage customers is $1.43 per kW per month of billing demand.[464] The demand charge was determined by computing the distribution demand-related revenue requirements from the electric cost-of-service study for primary and secondary voltage service under LG&E standard demand/energy rates (LC, LC-TOD, LP and LP-TOD) and dividing this amount by the billing demands for this class of customers.[465]

C. Changes to LG&E Gas Rate Schedules.

Under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a customer charge for Rate RGS of $8.50 per month is reasonable. No increase is proposed for the monthly Customer Charge for Rates CGS and IGS. LG&E is also proposing no modification to the off-peak pricing provision for those rates.[466]

Rates G-6 and G-7 are to be consolidated into a new As Available Gas Service Rate ("Rate AAGS").[467] This rate is proposed to be revenue neutral with respect to Rates G-6 and G-7 taken together.[468] Under the terms of the Partial Settlement, Stipulation and Recommendation, the parties have agreed that a Rate AAGS Customer Charge of $150 per month would be

[461] Id. at 82.
[462] Id.
[463] Id.
[464] Id.
[465] Id.
[466] Id. at 40.
[467] Id.
[468] Id. at 40-41.

reasonable.[469] LG&E is proposing no increase to Rate FT, Firm Transportation Service (Non-Standby), or to the special contracts.[470] An increase to these rates cannot be justified since the rate of return for this class of customers is 30.53%.[471]

Under the terms of the Partial Settlement, Stipulation and Recommendation, LG&E has agreed to withdraw its Standard Riders for Summer Air Conditioning Service for its gas operations. Customers served under those riders would take service under otherwise applicable rate schedules.[472]

LG&E is proposing a slight change to its Weather Normalization Adjustment clause ("WNA"). The WNA was recently extended to April 30, 2006, in Case No. 2003-00357.[473] Currently, the WNA is applied during the period from December through April. Under the proposal in this proceeding, the WNA would be applied during the period November through April.[474] The change is proposed because there are often significant heating degree-days during November.[475]

In addition, to the foregoing rate changes, LG&E is proposing changes to the terms and conditions of certain of its gas rate schedules. One of the proposed changes relates to Rate FT, a natural gas transportation only service available to customers who use more than 50 Mcf per day.[476] LG&E is proposing to modify the method for calculating the cash-out price under the cash-out mechanism.[477]

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469 Partial Settlement, Stipulation and Recommendation at LG&E Gas Exhibit 1, p. 6 of 9.
470 Seelye LG&E Direct at 41.
471 Id.
472 Partial Settlement, Stipulation and Recommendation at Section 3.11.
473 *In the Matter of: Application of Louisville Gas and Electric Company to Extend Its Gas Weather Normalization Adjustment Clause*, Case No. 2003-00357, Order dated October 30, 2003.
474 Seelye LG&E Direct at 41.
475 Id.
476 Direct Testimony of Clay Murphy of December 29, 2003 (Case No. 2003-00433) ("Murphy LG&E Direct") at 15.
477 Id. at 21.

It is in the best interests of both LG&E and its residential and commercial sales customers to limit daily and monthly imbalances to the extent practicable to maintain system reliability and to avoid increases in the costs paid by those customers.[478] Further, because LG&E will be purchasing under-deliveries at the lowest price and selling over-deliveries at the highest price, sales customers will benefit as those prices are reflected in the Gas Supply Clause.[479]

LG&E also proposes a change in the notification period for Operational Flow Orders ("OFO") in its Rate FT tariff. By way of an OFO, LG&E can direct a Rate FT customer to either (1) deliver to LG&E at least as much gas as it is using (in general, a potential under-supply situation), or (2) use at least as much gas as it is delivering to LG&E (typically, a potential over-supply situation).[480] If it fails to comply with an OFO, the customer can be financially penalized, in addition to other actions, such as physical isolation or curtailment.[481] The financial penalty for violating an OFO is $15.00 per Mcf plus the price of the gas on the day of the violation, which penalty is returned to the sales customers through the Gas Supply Clause.[482] All parties have agreed that the OFO notice period should be 24 hours, which has been in effect since the rate was first approved in 1995.[483]

LG&E is also proposing two minor changes to Rate FT relating to Remote Metering. These changes will clarify that the customer is responsible for paying for any modifications necessary to effectuate the installation of remote metering equipment and that the customer's required electric and telephone service must meet the specifications of LG&E.[484]

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478 Id. at 23.
479 Id.
480 Id. at 24.
481 Id.
482 Id.
483 Partial Settlement, Stipulation and Recommendation at Section 3.7.
484 Murphy LG&E Direct at 26.

In addition to the foregoing changes to Rate FT, LG&E is also proposing changes to Rate TS. This is the schedule under which LG&E provides standby sales service to its transportation customers. Unlike the Rate FT customers, Rate TS customers are not subject to daily balancing requirements or OFO provisions because these customers pay the costs associated with daily balancing and standby supply through their total sales rate.[485] LG&E is proposing to modify the cash-out mechanism applicable to over-deliveries by customers served under Rate TS. The proposed cash-out mechanism for over-deliveries by Rate TS customers will mirror the cash-out mechanism for over-deliveries under Rate FT.[486] The rationale for the change is the same as that set forth above for the similar change to Rate FT.

D. <u>The proposed Non-Conforming Load Service Tariff is fair and reasonable.</u>

On October 10, 2003, both Companies filed Applications with the Commission to establish a new tariff for non-conforming load service customers ("Rate NCLS").[487] As previously discussed, the Companies filed a motion to consolidate the NCLS tariff applications with and into the Companies' pending rate cases. On March 23, 2004, the Commission agreed to the consolidation and ordered KU to serve NAS during the interim under the terms of Rate NCLS after March 31, 2004, subject to possible refund.[488]

1. Impact of Non-Conforming Loads

For several years, the Companies have recognized that their quality of service and low cost were attracting interest from loads that did not conform to the typical customer's usage

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[485] Id.

[486] Id. at 27.

[487] *In the Matter of: Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers*, Case No. 2003-00396, Application dated October 10, 2003.

[488] *In the Matter of: Tariff Filing of Kentucky Utilities Company and Louisville Gas and Electric Company for Non-Conforming Load Customers*, Case No. 2003-00396, Order dated March 23, 2004.

characteristics or for which the system was designed.[489] A customer's load is described as non-conforming if that load "either increases or decreases 20 MVA or more per minute or 70 MVA or more in 10 minutes when such increases or decreases exceed one occurrence per hour during any hour of the billing month."[490] Such non-conforming loads can result in significant costs distributed among the entire customer base unless otherwise handled through special contracts or under a specifically-designed tariff.[491] The proposed Rate NCLS, now renamed Large Industrial - Time of Day (LI-TOD), is designed to acknowledge these unusual usage characteristics and ensure that the costs unique to non-conforming loads are properly allocated.[492]

In terms of operation, non-conforming loads are difficult for electric utilities. In general, their facilities are designed to handle gradual changes in load.[493] For the smaller loads managed by the Companies, rapid changes may not have any significant impact because a rapid increase in one small load can be easily offset by a rapid decrease in another small load - load diversity.[494] Even if this offset is not possible, it is relatively easy to quickly cover with minor changes in generation.[495] However, unlike small loads, the Companies have few larger loads, which reduces the possibility to offset with another large load.[496] Moreover, the Companies have a limited number of available generating units to ramp up and down in order to serve such a rapid change.[497]

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489 Direct Testimony of Charles A. Freibert, Jr. of October 10, 2003 (Case No. 2003-00396) ("Freibert NCLS Direct") at 1.
490 Id. at 2.
491 Id. at 1-2.
492 Id. at 2.
493 Id. at 3.
494 Id.
495 Id.
496 Id. at 3-4.
497 Id. at 4.

2. Determination of Rate LI-TOD

In these proceedings, the Companies proposed an NCLS tariff similar to that which was earlier proposed with the original NCLS tariff filing. In fact, the methodology used in calculating the proposed tariffs is also consistent with the methodology used for the NAS special contract rate approved by the Commission.[498] The calculation for the KU tariff uses the approved KU LCI-TOD rate schedule as a base.[499] Following the selection of a load level, that load level is billed on the approved LCI-TOD rate at the system average load factor in order to determine the appropriate revenue.[500] The proposed energy charge was then set at $0.01750/kWh to establish an ideal energy charge of fuel plus approximately 2-3 mills of other variable cost.[501] This is approximately the KU fuel base of $0.01494/kWh plus the other variable cost of 2-3 mills with the remainder of the revenue embedded in the proposed demand charges.[502] The LG&E tariff was calculated similarly. A different energy charge is used for LG&E because the fuel base is $0.01281/kWh plus the other variable cost of 2-3 mills.[503]

Under the Partial Settlement, Stipulation and Recommendation, a new rate LI-TOD was developed using a methodology that borrows from that described above, but which provides such customers with an incentive to control its load and reduce the fluctuations which KU experiences. The parties agreed to use the LCI-TOD rate as the base, with its lower demand charge and with its higher energy charge. The parties also agreed to a two-phase process in calculating the demand charge. The first phase measures the demand in standard fifteen minute intervals for billing. The second phase measures the demand in five and fifteen minute intervals

[498] Direct Testimony of F. Howard Bush, II of October 10, 2003 (Case No. 2003-00396) ("Bush NCLS Direct") at 1.
[499] Id.
[500] Id. at 1-2.
[501] Id. at 2.
[502] Id.
[503] Id.

and applies one-half the rate to the difference. That more accurately measures the true demand imposed by the customer and provides encouragement to the customer to control its load.

3. Rate LI-TOD is fair and reasonable in its general application.

Energy charges recover variable costs which are incurred by the Companies only to the extent a customer uses the system or offered services.[504] As a result, variable costs are recovered from a customer only to the extent it uses the system. In contrast, demand charges recover fixed costs which are incurred by the Companies whether or not a customer actually uses the system or offered services.[505] A specifically-designed tariff will adequately compensate the Companies for the service they provide and protect their other customers from bearing a cost for which they are not responsible.[506] Transferring cost to demand charges also provides added efficiency for ratepayers; a customer who receives the correct price signal is better able to control its billing.[507]

In essence, the Companies seek a fair and reasonable accounting of the generation capacity that a non-conforming load customer continuously requires from the Companies' system.[508] Because of the particular usage characteristics of a non-conforming load, the Companies have requested a five-minute interval for determining metered demand.[509] Fifteen-minute demand intervals may work well for smaller loads or loads with gradual change that allow the system to compensate accordingly.[510] Yet the rapid load swings of a non-conforming load simply necessitates a shorter demand interval in order to insure that such customers do not tie up facilities without paying for them and to give them proper price signals.[511] In fact, a five-

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[504] Id.
[505] Id.
[506] Id. at 2-3.
[507] Id. at 3.
[508] Id.
[509] Id.
[510] Id. at 3-4.
[511] Id. at 4.

minute demand has been ordered and approved in a number of situations by other state regulatory agencies.[512]

By splitting the difference in metered demand charges as measured in five and fifteen minute intervals, the customer is given an incentive to control its load while the Companies can collect demand charges which reasonably account for the unique loads of these large customers.

The new LI-TOD tariff represents a fair and reasonable compromise in that it creates incentives for this customer class to control its load and mechanisms for KU to recover a level of demand charges from such industrial customers that is more commensurate with the additional costs associated with serving customers with these load characteristics.

4. Rate LI-TOD is fair and reasonable as applied to NAS.

Effective April 1, 2001, KU entered into a three-year contract with NAS to provide electric service for the operation of an electric arc furnace at its stainless steel production facility in Carrollton, Kentucky. The Commission approved this special contract on April 26, 2001.[513] In accordance with the express notice provisions of the special contract, NAS notified KU that it was terminating the contract at the end of the initial term. While KU was preparing to commence a proceeding to establish a new rate for NAS and any other non-conforming load that might come onto KU's system, NAS filed a formal complaint with the Commission against KU on September 23, 2003, and requested service under the LCI-TOD tariff once the special contract

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[512] *See Sierra Pacific Power Company*, No. 82-08-43, 1983 Cal. PUC LEXIS 901(Cal Pub. Util. August 19, 1982); *Pacific Gas and Electric Company*, No. 97-09-047, 1997 Cal. PUC LEXIS 867; 75 CPUC2d 349 (Cal. Pub. Util. Sept. 3, 1997); Southern *California Edison Company*, No. 87-12-066, 1987 Cal. PUC LEXIS 415; 26 CPUC2d 392 (Cal. Pub. Util. Dec. 22, 1987); Southern *California Edison Company*, No. 87-01-017, 1987 Cal. PUC LEXIS 415; 26 CPUC2d 392 (Cal. Pub. Util. Dec. 22, 1987); San *Diego Gas & Electric Company*, No. 98-06-049, 1998 Cal PUC LEXIS 490; 80 CPUC2d 507 (Cal. Pub. Util. June 18, 1998); *Portland General Electric Company*, No. 01-777, 2001 Ore. PUC LEXIS 415; 212 P.U.R.4th 1 (Ore. Pub. Util. Aug. 31, 2001); Delmarva *Power & Light Company*, No. 84-18, 1984 Del. PSC LEXIS 2 (Del. Pub. Serv. May 29, 1984).

[513] *In the Matter of: The Contract Filing of Kentucky Utilities Company to Provide Electric Service to North American Stainless*, Case No. 2000-542, Interim Order dated April 26, 2001.

expired.[514] KU then filed its new non-conforming load rate proceeding, and the NAS complaint was consolidated into that rate proceeding. As previously discussed, the Commission then agreed to address the rate classification for NAS in this base rate proceeding.

Though Rate LI-TOD applies to any customer with a non-conforming load, only NAS currently fits into the class covered by the proposed tariff. This does not mean that Rate LI-TOD was designed for NAS. Careful consideration was given to the problem of serving any customer with a large and volatile load, whether it is NAS or others who might approach the Companies in the future. Rate LI-TOD simply attempts to charge those customers with atypical loads for their fair share of the cost to serve. The fact that NAS infrequently uses the generation it demands in no way means that KU incurs no cost to ensure that the generation is available to serve NAS when NAS demands it. In operation, the Companies must plan separately to guarantee that sufficient additional capacity is available to serve rapid changes generated by that non-conforming load.[515] Essentially, the Companies are forced to hold back capacity solely with respect to a non-conforming load customer to the potential detriment of other customers.[516] It would be irresponsible for the Companies not to protect all of their ratepayers from the unusual characteristics of a few who have such atypical usage patterns.

The load characteristics of NAS and other future large, fluctuating load customers are significantly different from those customers in the LCI-TOD rate classification. KU's existing LCI-TOD tariff, in fact, does not apply to loads above 50 MW like NAS's electric arc furnace.[517] Again, these atypical load characteristics present the Companies with a unique and difficult challenge in terms of service and cost of service. The compromise effectuates a reasoned and

[514] *In the Matter of: North American Stainless, Complainant v. Kentucky Utilities Company, Defendant*, Case No. 2003-00376.
[515] Freibert NCLS Direct at 5.
[516] Id.
[517] Id. at 2.

balanced method of collecting higher demand charges more reflective of NAS' unique load characteristics while providing incentives for NAS (through the demand surcharge) to control its load to its benefit and to the benefit of KU's generation system. Moreover, KU has preserved the necessary system contingency provisions which enable it to assure the integrity of its generation system.

Conclusion

For all of the reasons stated herein, Louisville Gas and Electric Company and Kentucky Utilities Company request the Commission to enter an order by June 30, 2004:

1. approving the ESM Settlement Agreement;

2. approving so much of the Partial Settlement, Stipulation and Recommendation which represents a complete settlement among all the parties on all the issues set forth therein, including, but not limited to:

    a. effective July 1, 2004, the annual increase in revenues for LG&E gas operations of $11,900,000 as set forth in Sections 1.2 and 2.2;

    b. allocation of the annual increases in revenues for LG&E gas and electric customers and KU electric customers as set forth in Section 2.1;

    c. establishment of a pilot time-of-day program for LG&E's and KU's electric commercial customers with a monthly demand between 250 kW and 2,000 kW as set forth in Section 2.3;

    d. treatment of the specific issues set forth in Article III, Sections 3.1 - 3.2 and 3.4 - 3.23 (*e.g.* the real-time pricing program for LG&E's electric customers in Section 3.6 and the Home Energy Assistance programs in Sections 3.14 - 3.17); and

    e. all other tariff changes proposed by LG&E and KU.

3. approving an increase in LG&E's electric revenues, effective July 1, 2004, of at least the $43,400,000 set forth in Sections 1.1.1 and 2.2 of the Partial Settlement, Stipulation and Recommendation and rejecting the AG's contentions concerning this issue; and

4. approving an increase in KU's electric revenues, effective July 1, 2004, of at least the $46,100,000 set forth in Sections 1.1.2 and 2.2 of the Partial Settlement, Stipulation and Recommendation and rejecting the AG's contentions concerning this issue.

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Respectfully submitted,

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The undersigned hereby certifies that a true and correct copy of the foregoing Joint Post-Hearing Brief was served on the following persons on the 4th day of June 2004, United States mail, postage prepaid:

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